Comparison of Transmission Loss Allocation Methods and Prediction of Losses in Deregulated Power Systems

by

MATEMEKE EDWINAH MAREDI

DISSERTATION

Submitted to the
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CERTIFICATION OF APPROVAL

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____

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Univesiti Teknologi PETRONAS
Tronoh, Perak
December 2010

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

MATEMEKE EDWINAH MAREDI

ABSTRACT

Transmission losses are a significant component of the amount of power to be generated in order to meet the power demand. Today, in competitive electric energy markets operating under pool-based, bilateral contracts or hybrid model, transmission losses must be allocated among the market participants. This process should take to account the buyer and seller spatial locations on the network as well as the non-linear interaction among simultaneous transactions in order to reflect the real market operation and adequate economic efficiencies. In this paper, four methods for transmission loss allocation in power systems operating in a deregulated competitive environment are discussed and compared. Losses for oncoming operations are then predicted. Test results using the IEEE 24-bus RTS are presented. Relevant conclusions, comments and suggestions are also included.

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CHAPTER 1

INTRODUCTION

1.1 Background of Study

In many countries, electricity industries are being restructured and liberalized. Electricity is now a commodity, bought and sold by generators, retailers (suppliers) and other traders. Vertically integrated utilities are being broken up, which allows end-users and distributors to buy power from more distant generators.

Deregulation of electricity is the process by which the government removes or reduces the restrictions of the electricity industry. The electric utility is no longer under the control of one organization. The main aim of deregulation is to improve competition among the electricity retailers, which improves the efficiency of the industry and electricity pricing.

In a deregulated market, there are several retailers using the same transmission company. This poses a problem of having to distribute the losses that occur during transmission and distribution in a fair manner among the retailers. This is where transmission loss allocation comes in. Transmission loss allocation deals with the allocation of transmission losses among the retailers.

There are various methods for transmission loss allocation. Various methods for loss allocation will be studied and compared to study the advantages and disadvantages of these methods. The methods to be researched include pro rata, incremental loss, unsubsidized incremental, proportional sharing method.

1.2 Problem statement

The introduction of deregulation into the electricity market has changed many aspects of the industry. The reform required reorganization and rethinking of the traditional issues of power balance, stability, security and economy. Previously vertically integrated industry comprising of generation, transmission and distribution sectors had been decomposed into separate independent entities. New market structures were introduced in which markets are modeled by either pool, bilateral contracts, or a combination of both called the hybrid [1]. These deregulated markets are governed by System Operators that monitor the daily operation of the market, as well as ensuring a secure operation and facilitating an economical operation.

The pricing of electricity has always been a major concern to system participants, even before the introduction of deregulation. The previous monopolistic structure used a simple pricing scheme based on a uniform distribution of the approximated loss of 2 % to 5 % of generated power. This simple loss allocation, however, is not sufficient for the restructured electricity market as it does not encourage competition between market participants. Given that healthy competition should encourage lower prices, it is important to develop an electricity-pricing scheme that promotes competition.

To promote fair competition, market participants must be charged in a way that reflects their use of the system. A critical part of this is the distribution of system losses to the market participants.

Even though there are different methods for loss allocation, they all allocate losses in different ways. The choice of a method depends on the desired results and the system settings.

There is sometimes also a problem of the power supply not meeting the demand, so to avoid power failures and such problems, it's important for the suppliers to know how much the demand is. That's were prediction of oncoming operations is of importance.

1.3. Objectives

- To do a study of deregulated systems.
- To do research and study various methods of loss allocation.
- Compare the methods to see the differences and similarities.
- Do qualitive and quantitive measurements to see which method produces better results.
- Predict transmission losses for oncoming operating scenarios.

1.4 Scope of Study

This project involves detailed research on transmission loss allocation in deregulated systems. There will be journals reviewed based on transmission loss allocation in various settings.

Various methods for loss allocation will be looked into and discussed in detail to do a comparison.

Prediction of transmission losses in a transaction for oncoming scenarios will also be performed.

CHAPTER 2
LITERATURE REVIEW

2.1 Deregulation

Electricity markets around the world are undergoing major changes to improve the economic efficiency and effectiveness of electricity supply. To promote competition, previously vertically integrated utilities have been broken up into separate generation, transmission and retailing companies. In addition, open electricity markets have been formed to facilitate the trading of electricity.

An electric system, as illustrated in figure 1, consist of three main parts; generation, transmission and distribution.

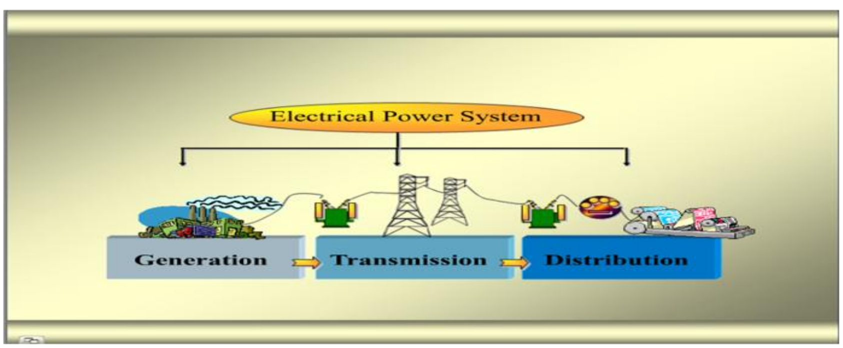

Figure 1: A regulated electric system

In a regulated system, the generation, transmission and distribution are the responsibility of a single organization. Figure 2 illustrates,

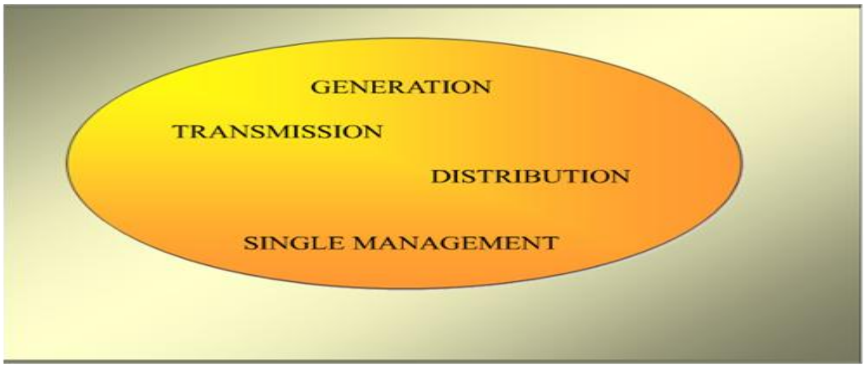

Figure 2: An illustration of a regulated system

In a deregulated structure however, a transmission system is being used by multiple generation and distribution companies that do not own the transmission system, as illustrates in figure 3.

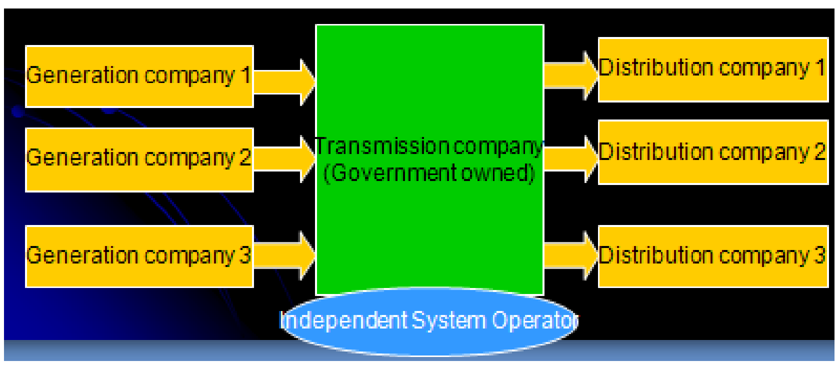

Figure 3: An illustration of a deregulated system

In view of the operation of deregulated systems, it becomes more important to know the role of individual generators and loads to transmission wires and power transfer between individual generators to loads. Under restructuring and deregulation, vertically integrated utilities, which producers generate, transmit and distribute electricity, have been functionally unbundled. Deregulation introduces completion in the wholesale generation and retailing of electricity.

With separate pricing of generation, transmission and distribution, it is necessary to find the capacity usage of different transactions happening at the same time so that fair usage-of–transmission-system charge can be given to individual customer separately. That way, transparency in a deregulated system can be achieved. Capacity usage is an important issue for transmission; therefore, the power produced by each generator and consumed by each load should be traced. In these aspects, problems arise because all transactions have to share the same transmission network simultaneously.

Those problems include

- Which generators are supplying this load?
- Which generator or load is making the biggest use of the transmission line?
- Which generator or load is producing loss of this transmission line?

need to have acceptable solutions in a fair deregulated system [1].

2.2 Loss allocation methods

To solve the problem of loss allocation in a deregulated system, an algorithm, which can allocate the contributions of power flow and loss from individual generator through the transmission system to the loads, is needed. More sophisticated treatment of losses, in contrast to traditional methods that arbitrarily assign losses as 2 % to 5 % of generated power, is critical in overcoming this problem [2]. Essentially, the loss allocation chosen is a part of the design of the market itself.

A carefully selected loss allocation method must be able to do the following:

- promote efficient matching of supply and demand;
- provide indicative measures for location advantages of market participants; and
- provide information on the need and appropriate location of network expansions.

It is crucial for market operators of the deregulated market to adopt loss allocation methods that are compatible with their market structures, as well as promoting competition between market participants. Different markets globally have employed different loss allocation schemes, no loss allocation method has been universally accepted. In Australia the National Electricity Market (NEM), which is managed by the National Electricity Market Management Company (NEMMCO) has used a form of approximated marginal loss allocation [3]. In contrast, the Great Britain, Spain and Brazil market has employed the simpler pro rata method [4]. Furthermore, New Zealand has adopted the full marginal loss allocation method [5].

The fact that not a single method of loss allocation can be universally accepted suggests that there are deficiencies in all current methods, leading to continued research in this field. Some methods are so unsatisfactory that some markets, such as Brazil, to consider implementing alternative approaches [6].

Among some of the currently used methods for loss allocation are pro rata, marginal, proportional sharing, loss formula, and circuit theory based [7].

We will review four of these methods, namely, pro rata, proportional sharing, incremental transmission loss (ITL) and unsubsidized incremental transmission loss (U-ITL).

2.2.1. Pro rata method

The simplest method is the pro rata method, which is based on an arbitrary division of losses between active generation and load.

First, losses are globally assigned to generators and consumers, for instance 50 % of losses are allocated to each category. Then, a proportional allocation rule is used: the losses allocated to a generator (consumer) are proportional to its corresponding level of energy generation (consumption). A PR procedure is currently used in the electricity market of mainland Spain where 100 % of losses are allocated to consumers [8].

The advantage of pro rata procedures are simple to understand and implement. The disadvantage of this method is that it does not take account of the geographic distribution of the network. It “ignores” the network. That is, two identical demands located respectively near generating buses and far away from these buses are equally treated, and this is unfair for the load located near the generating buses [9].

2.2.2 Marginal Procedures (ITL) and Unsubsidized ITL

Loss allocation using the incremental method is fundamentally simple, being based on the concept of numerical integration. However, the incremental results depend on the formulation of the marginal-loss function which is, in turn, governed by how the system evolves to a current state through incremental power changes [10]. In all existing methods, the marginal-loss functions are derived using certain user-defined and arbitrary criteria to maintain the load-generation balance for small power changes. These criteria may or may not reflect the actual performance of the system. As such, the resulting allocations are at best theoretical and can have little practical application for costing purposes.

Losses are assigned to generators and demands through the so-called incremental transmission loss (ITL) coefficients [11]. Normalization is performed after the assignment because this allocation procedure typically results in over-recovery. The standard marginal procedure based on ITL coefficients depends on the selection of the slack bus because ITL coefficients do depend on the slack bus. The ITL coefficient of the slack bus is zero by definition, thus the slack bus is allocated no losses. This is a drastic limitation for this method that requires that pool agents agree beforehand on the selection of the slack bus. Furthermore, ITL coefficients can be either positive or negative which may result in the allocation of negative losses to certain buses. The unsubsidized marginal allocation (U-ITL) can be used to get rid of these negative losses.

2.2.3 Proportional sharing procedure (PS)

The use of the results of a converged power flow plus a linear proportional sharing principle [12] makes it possible for the allocation of losses to generators and consumers. This principle states that the power flow reaching a bus from any power line splits among the lines evacuating power from the bus proportionally to their corresponding power flows, which is neither provable nor disprovable.

Proportional sharing procedures, on top of electrical laws, require the assumption of the proportional sharing principle. Using this principle, losses are allocated by linear procedures. To allocate losses to demands, the method relies on a simple principle: losses associated with every line whose flow enters a given bus are transferred to the lines whose flows leave the bus (or demands in that bus) proportionally to the flows of those lines (the flows of which leave the bus). It should be noted that a systematic application of this principle originates that all losses are allocated to demands. Analogously, in order to allocate losses to generators, the method relies on a simple principle: losses associated with every line whose flow leaves a given bus are transferred to the lines whose flows enter the bus (or generations in that bus) proportionally to the flows of those lines (whose flows enter the bus). It should be noted that a systematic application of this principle originates that all losses are allocated to generators. The sole information required to apply this method is the real power flow and the losses in every line, and the power generated or consumed in every bus.

Due to the fact that no unique or ideal procedure exists, any loss allocation algorithm should have most of the desirable properties stated below:

- to be consistent with the results of a power flow
- to depend on the amount of energy either produced or consumed
- to depend on the relative location in the transmission network
- to avoid volatility
- to provide appropriate economic marginal signals
- to be easy to understand
- to be simple to implement

2.3 Prediction of Losses in a Transaction

A generalized quadratic relationship can be used to learn the relationships between a retailer's demand and the line losses in each line used by a transaction, by generating learning coefficients [13]. The current operating scenario and a few past operating scenarios related to a specific transaction can be used to generate the coefficients. Using the generated learning coefficients, power loss for a transaction for any oncoming operating scenario can be determined.

These relationships exist as long as the network configuration remains unchanged and the voltages at the retailing points are restored close to their original values. These relationships, for a specific network configuration, can be learned through learning coefficients and these learning coefficients can be used to determine the corresponding power loss for a transaction.

2.4 Power flow tracing

In [14], Bialek presents a power for tracing method that can be used for transmission loss allocation. The method may be applied to both real and reactive power flows. The method allows assessment of how much of the real and reactive power output from a particular station goes to a particular load. It also allows the assessment of contributions of individual generators or loads to individual line flows. A loss partitioning algorithm has also been introduced which allows the break down of the total transmission loss into components to be allocated to individual loads or generators.

The mesh structure of high-voltage transmission networks provides a large number of possible routes by which electrical power can flow from the source (generators) to the sinks (loads). Tracing the connections using the load flow program is not possible as changing demand as changing demand or generation at any node would result in a corresponding change of generation coming from the marginal plant. Hence, the conventional wisdom is that with an integrated system, it is not possible to trace electricity from a particular generator to a particular supplier.

It is only possible to determine relation between the generators (or loads) and the flows of in transmission lines by means of sensitivity analysis, that is by determining how a change in a nodal generation/demand influences the flow in a particular line.

The method of tracing is of particular interest especially in deregulated systems. In this context, the problem of tracing gains importance as its solution could enhance the transparency in the operation of the transmission system. An electricity tracing method will make it possible to charge the suppliers and/or generators for the actual amount of losses caused and hence encourage efficiency. Whether or not a generator or supplier should be penalized for its graphical location is not considered in this case.

The tracing method used here is topological in nature; it deals with a general transportation problem of how the flows are distributed in a meshed network. For the tracing method used in [13], the network is assumed to be connected and described by a set of *n* nodes, *m* directed links (transmission lines or transformers), 2m flows (at both ends of each link) and a number of sources (generators) and sinks (loads) connected to the nodes. Practically the only requirement for the input data is that Kirchhoffs Current Law must be satisfied for all the nodes in the network. In this respect the method is equally applicable to real and reactive power flows and direct currents. Neglecting the Kirchhoff s Voltage Law does not introduce any further errors as the law has been already used to obtain the flows.

The main principle used to trace the flow of electricity will be that of proportional sharing [13]. This is illustrated in figure 1 where four lines are connected to node ***i*****,** two with inflows and two with outflows. The total power flow through the node is P*i* = 40 + 60 = l00MW of which 40% is supplied by line *j-i* and 60% by line *k-i.* As electricity is indistinguishable and each of the outflows down the line from node *i* is dependent only on the voltage gradient and impedance of the line, it may be assumed that each MW leaving the node contains the same proportion of the inflows as the total nodal flow P***i*****.** Hence the 70MW outflowing in line *i-m* consists of 70*40/100 = 28MW supplied by line *j-i* and 70*60/100 = 42MW supplied by line *k-**i*****.** Similarly the 30MW outflowing in line *i-1* consists of 30*40/100 = 12MW supplied by line *j-i* and 30*60/100 = 18MW supplied by line *k-i*.

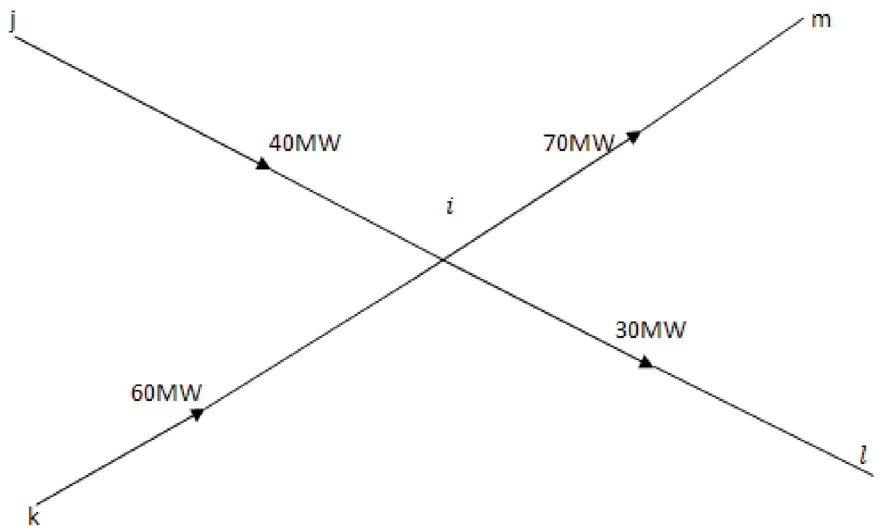

Figure 4: Proportional sharing principle

The proportional sharing principle basically amounts to assuming that the network node is a perfect ‘mixer’ of incoming flows so that it is impossible to tell which particular inflowing electron goes into which particular outgoing line. This seems to agree with common sense and with the generally accepted view that electricity is indistinguishable. As it is impossible to ‘dye’ the incoming flows and check the color of the outflows, the proportional sharing principle can be neither proved nor disproved. This, however, is irrelevant as the principle will be applied here for nontechnical calculations. In this respect, the principle is fair as it treats all the incoming and outflowing flows in the same way. In other words, no particular generator or load is distinguished in any way.

Tracing electricity can be seen as a transportation problem of determining how the power injected by generators is distributed between the lines and loads of the network. The algorithm proposed works only on lossless flows when the flows at the beginning and end of each line are the same. In the simplest way of obtaining lossless flows from the lossy ones is by assuming that a line flow is an average over the sending- and receiving-end flows and by adding half of the line loss to the power injections at each terminal node of the line.

Consider for example a simple system shown in Figure 2 with active and reactive power flows obtained from AC load flow program. A number on top or to the left of the line indicates a real power flow, while a number below or to the right of the line indicates a reactive power flow. A similar convention has been used for the generators and the loads. The total transmission loss in the network is equal to the sum of all the line losses and equals (225 - 218) + (83 - 82) + (173 - 171) + (60 - 59) + (115 - 112) = 14MW.

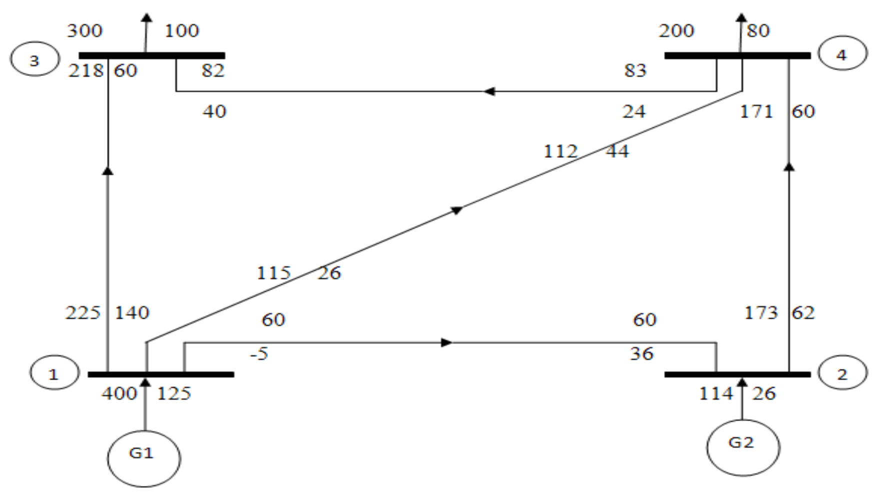

Figure 5: AC power flow in four node network

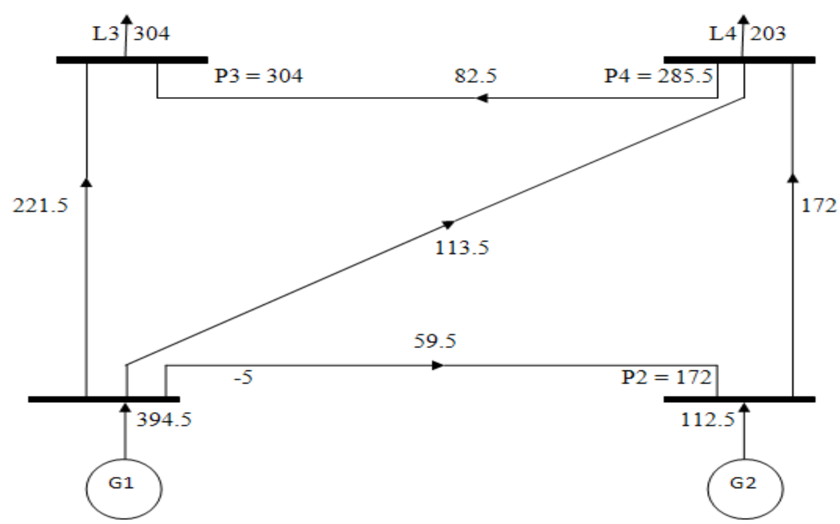

Figure 6: Lossless power flow

Figure 3 shows a lossless real power flow obtained from the lossy flow of figure 2.

The algorithm for tracing the flow of electricity will be now derived in two versions. The downstream-looking algorithm will look at the nodal balance of outflows while the dual, upstream-looking algorithm, will look at the nodal balance of inflows [13]. The upstream-looking algorithm will apportion the losses to the loads and allocate the supplement charge to the generators. The downstream-looking algorithm will apportion the losses to the generators and allocate the supplement charge to the loads.

Upstream-looking algorithm

Assume that it is possible to break down the total transmission loss into components to be added to individual load demands. The sum of the actual demand of a particular load plus the allocated part of the total transmission loss is referred to as the gross demand. Obviously the total system gross demand is equal to the total actual generation.

Downstream-looking algorithm

The downstream-looking algorithm allocates the supplement charge to individual loads. The transmission loss is dealt with by breaking it down into components to be subtracted from individual generators. The actual generation of a particular generator minus the allocated part of the total transmission loss will be referred to as the net generation.

One of the possible applications of the electricity tracing method lies in the apportioning of the transmission loss to individual generators or loads in the network. This can be done by accumulating the losses as the power flows to individual loads (or from individual generators). The nodal loss is assumed to be shared between nodal outflows proportionally to the square (or any other power) of the outflows. The loss allocation does not depend on the choice of the marginal generator and always results in positive charges. This algorithm requires solving a sparse linear equation of the rank equal to the number of network nodes.

It is envisaged that the proposed method could have wide applications in the deregulated electricity supply industry. Apart from giving additional insight into how power flows in the network, it can be used to set tariffs for transmission services based on the shared, as opposed to marginal, costs. This includes charging for the transmission loss and for the actual usage of the system by a particular generator or the load. The method can also be used to assess the contribution of individual sources of reactive power in satisfying individual reactive power demands and therefore be used as a tool for reactive power pricing

CHAPTER 3

METHODOLOGY

3.1 Procedure Identification

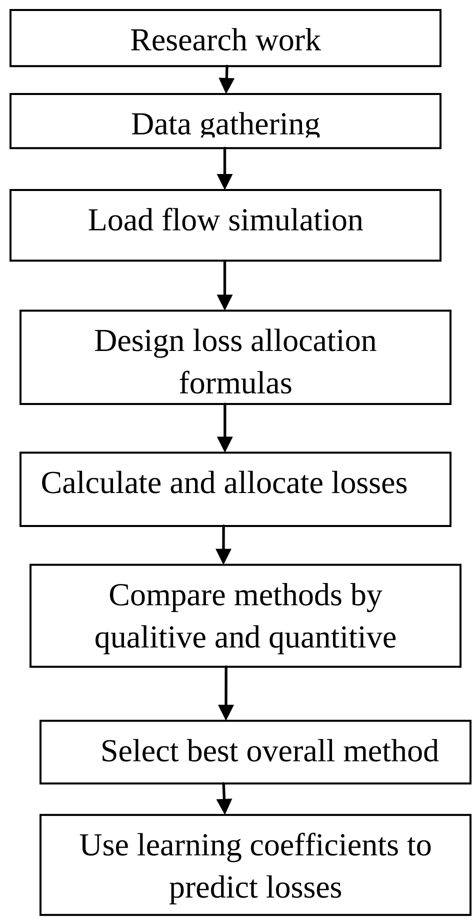

Figure 7: Flow chart of the project

3.2 Tools and equipment required

- Matlab
- Matpower

3.3 Applied method

First, note that the sum of all generations is equal to the sum of all demands plus the losses. That is

$$P_G = P_D + L,\ P_G = \sum_{i=1}^{N_G} P_{Gi}\ , P_D = \sum_{j=1}^{N_D} P_{Dj} \qquad (1)$$

where

P_G	=	total active power generated;
P_{Gi}	=	power output of generators of bus;
P_D	=	total active power demand;
P_{Dj}	=	active power demanded by consumers of bus j;
L	=	transmission power losses;
N_G	=	number of generating buses;
N_D	=	number of demand buses.

For simplicity and without loss of generality, it is assumed that in every bus there are at most one generator and one demand. Therefore, no distinction will be made henceforth between generator, load, and bus.

The considered transmission loss allocation methods are described in the four subsections below [10].

3.3.1 Pro Rata Allocation (PR)

The PR method proportionally allocates 50% of losses to the demands and 50% to the generators, that is

$$L_{Gi} = \frac{L}{2}\frac{P_{Gi}}{P_G}\ , \quad L_{Di} = \frac{L}{2}\frac{P_{Di}}{P_D} \qquad (2)$$

where L_{Gi} is the losses allocated to the generator i, L_{Dj} and are the losses allocated to the demand j . Generation and demand loss allocation factors are computed, respectively, as

$$L_{Gi} = \frac{1}{2}\frac{P_{Gi}}{P_G} = K_G P_{Gi} \,, \qquad K_G = \frac{1}{2}\frac{L}{P_G} \tag{3}$$

$$L_{Di} = \frac{1}{2}\frac{P_{Dj}}{P_D} = K_D P_{Dj} \,, \qquad K_D = \frac{1}{2}\frac{L}{P_D} \tag{4}$$

It should be noted that generation loss allocation factors K_G are identical for all buses, and demand loss allocation factors $K_D$are also identical for all buses. Additionally, it should be noted that losses allocated to generators and demands are always positive.

3.3.2 Marginal Allocation (ITL)

This method uses ITL coefficients to proportionally allocate losses to generators and demands. ITLs are easily obtained from a converged power flow [15]. The ITL of a given bus provides the change in total losses produced by an incremental change in the power injected in that bus. Therefore

$$K_i = \frac{\partial L}{\partial (P_{Gi} - P_{Di})} \tag{5}$$

where K_i is the ITL corresponding to bus . It should be noted that the ITL of the slack bus is zero by definition.

First computations of the losses allocated to generator i and demand j are, respectively,

$$L_{Gi} = P_{Gi}\frac{\partial L}{\partial P_{Gj}} = P_{Gi} K_i \tag{6}$$

$$L_{Di} = P_{Di} \frac{\partial L}{\partial P_{Dj}} = -P_{Di} K_j \tag{7}$$

However as a result of nonlinearities, the sum of these allocated losses ($L^{'}$) does not match total actual (measured) losses$L$. Therefore, a normalization procedure is used to allocate the exact amount of losses L, that is

$$L \neq \sum_{i=1}^{N_G} L_{Gi} + \sum_{j=1}^{N_D} L_{Dj} = \sum_{i=1}^{N_G} P_{Gi} K_i - \sum_{j=1}^{N_D} P_{Dj} K_j = L' \tag{8}$$

Therefore a normalization procedure is used to allocate the exact amount of losses L

$$\begin{aligned} L = L' \frac{L}{L'} &= \left(\sum_{i=1}^{N_G} P_{Gi} K_i - \sum_{j=1}^{N_D} P_{Dj} K_j \right) \frac{L}{L'} \\ &= \sum_{i=1}^{N_G} P_{Gi} K_i' - \sum_{j=1}^{N_D} P_{Dj} K_j' \end{aligned} \tag{9}$$

where $K_i' = K_i (L/L')$ is the normalized ITL coefficient for bus i.

Finally, losses allocated to every generator and demands are, respectively,

$$L_{Gi}^{'} = P_{Gi} K_i^{'} \quad L_{Dj}^{'} = -P_{Dj} K_j^{'} \tag{10}$$

It should be noted that this marginal procedure may allocate negative losses to either generators or demands, and these negative losses can be interpreted as cross subsidies [10].

3.3.2 Unsubsidized Marginal Allocation (U-ITL)

The unsubsidized ITL (U-ITL) method modifies in a consistent manner ITL coefficients so that negative losses are avoided. A set of ITLs is defined for generators and a different one for demands. The purpose of this method is to actually allocate the cost of losses, not to explain physical facts.

ITL coefficients, computed for a given slack bus, can easily be referred to a different slack bus by defining a translation coefficient $\beta(0 \leq \beta \leq 1)$ [10].

Total losses can be computed as

$$L = \sum_{i=1}^{N} K_i^{'} P_i \tag{11}$$

where

N number of buses;

$K_i^{'}$ normalized ITL coefficient of bus ;

P_i injected active power in bus $i(P_i = P_{Gi} - P_{Di})$.

Total losses can also be expressed as

$$L = \sum_{i=1}^{N} (P_{Gi} - P_{Di}) = \sum_{i=1}^{N} P_i \tag{12}$$

Multiplying (11) by $\beta(0 \leq \beta \leq 1)$ and (12) by $1 - \beta$, and adding both, total losses can be expressed as

$$L = \sum_{i=1}^{N} \beta K_i' P_i + \sum_{i=1}^{N} (1 - \beta) P_i \tag{13}$$

which results in

$$L = \sum_{i=1}^{N} [\beta K_i' + (1 - \beta)] P_i = \sum_{i=1}^{N} K_i P_i \tag{14}$$

where $\beta K_i' + (1 - \beta)$ constitutes a new ITL coefficient $K_i = \beta K_i' + (1 - \beta)$.

In respect to the generation, a change of slack bus is performed in such a way that the generator ITL coefficient with smallest value becomes zero. This makes it impossible to assign negative losses to generators. This is accomplished as stated below.

Let K'_{Gk}be the normalized generation ITL coefficient with the smallest value, the translation coefficient β_G is then computed as

$$K_{Gk} = 0 = \beta_G K'_{Gk} + (1 - \beta_G) \tag{15}$$

and

$$\beta_G = \frac{1}{1 - K'_{Gk}}$$

The new ITL coefficients for generators can be expressed as

$$K_{Gi} = \beta_G K'_{Gk} + (1 - \beta_G). \tag{16}$$

Those coefficients are again normalized to allocate 50% of losses to generators.

In respect to demands, the translation coefficient β_D is computed from

$$K_{Dm} = 0 = \beta_D K'_{Dm} + (1 - \beta_D) \tag{17}$$

where K'_{Dm} is the demand ITL coefficient with the highest value. Equation (17) guarantees that no demand gets allocated negative losses. Therefore, demand ITL coefficients become all negative.

From (17), $\beta_D = 1/(1 - K'_{Dm})$.

The new demand ITL coefficients become

$$K_{Dj} = \beta_D K'_{Dj} + (1 - \beta_D). \tag{18}$$

3.3.4 Proportional Sharing Allocation (PS)

This algorithm is a brief summary of Bialek's proportional sharing algorithm [14]. Losses are first allocated to demands and then to generators [10].

In respect to demands, a total gross demand including losses P_D^G is defined as

$$P_D^G = P_D + L \quad and \quad P_D^G = \sum_{j=1}^{N_D} P_{Dj}^G \qquad (19)$$

where P_{Dj}^G is the gross demand of bus j.

The total gross demand must equal the total generation so that $P_G = P_D^G$. Using the proportional sharing principle, the power balance in every bus of an equivalent lossless network becomes

$$P_i^G = P_{Gi} + \sum_{j\epsilon\alpha_i} c_{ji} P_j^G \quad where\ i = 1, \dots, N \qquad (20)$$

with

$$c_{ji} = \frac{P_{ji}^G}{P_j^G} \approx \frac{P_{ji}}{P_j} \qquad (21)$$

P_i^G	gross power injected at bus i;
P_{Gi}	generation in bus i;
$\sum_{j\epsilon\alpha_i} c_{ji} P_j^G$	power flow reaching bus i from lines connected to it.
α_i	set of buses from which power flows toward bus i;
P_{ji}^G	gross power flow from j to i;
P_{ji}	actual power flow from j to i (measured in j);
P_j	actual power injections in bus j.

Equation (20) constitutes a system of linear equations that can be solved easily for $P_i^G, i = 1, \dots, N$. New generations and losses are then computed, respectively, as

$$P_{Dj}^{G} = \frac{P_j^G}{P_j} P_{Dj} \; and \; L_{Dj} = P_{Dj}^{G} - P_{Dj} \tag{22}$$

Losses are assigned to generators. Total gross generation including losses P_G^G is defined as

$$P_G^G = P_G + L \; and \; P_G^G = \sum_{i=1}^{N_G} P_{Gi}^G \tag{23}$$

Where P_{Gi}^G is the gross generation of bus i, including losses.

The gross generation generation must be equal to the total demand, so that $P_G^G = P_D$. Using the proportional sharing principle, the power balance in bus i of an equivalent lossless network becomes

$$P_i^G = P_{Di} + \sum_{j \epsilon \gamma i} c_{ji} P_j^G\,, \quad where\; i = 1, \ldots, N \tag{24}$$

Where

P_i^G	gross power injected in bus i;
P_{Di}	demand in bus i;
$\sum_{j\epsilon\gamma i} c_{ji} P_j^G$	power flow leaving bus i;
γi	set of buses drawing power from bus i;

Equation (24) constitutes a system of linear equation that can be solved easily for $P_i^G, \;\; i = 1, \ldots, N$. New generations and losses are then computed respectively as

$$P_{Gi}^G = \frac{P_i^G}{P_i} P_{Gi} \quad and \quad L_{Gi} = P_{Gi} - P_{Gi}^G \tag{25}$$

In order to assign 50 % of losses to the generation and 50% to the demand, the final generation and demand per bus are computed as

$$P_{Gi}^{'} = \frac{P_{Gi}^{G} + P_{Gi}}{2} \quad and \quad P_{Dj}^{'} = \frac{P_{Dj}^{G} + P_{Dj}}{2} \tag{26}$$

Losses assigned to every generator and demand are, respectively,

$$L_{Gi}^{'} = P_{Gi} - P_{Gi}^{'} \qquad and \qquad L_{Dj}^{'} = P_{Dj}^{'} - P_{Dj}. \tag{27}$$

Generation and demand loss allocation factors are respectively computed as

$$K_{Gi} = 1 - \frac{P_{Gi}'}{P_{Gi}} \; and \; K_{Dj} = \frac{P_{Dj}'}{P_{Dj}} - 1 \tag{28}$$

3.3.5 Predicting Power Loss in a Transaction

Loss in a transaction is the difference between the generation's contribution to a demand at the generation end and the generation's contribution to a demand at the load bus. In order to implement a new direction involving competitive marketing of electric energy, it is necessary to know how the costs of providing electric energy vary. These variations the losses associated with generation, transportation and delivery of electricity. Learning coefficients enables learning of the relationship between a demand and the contributions to this demand through each possible transmission path based on the current and few past operational scenarios. Once these learning coefficients are obtained, they can be used to predict contribution of each generation to a retailer's future demand, and the share of the losses related to a transaction in a line. By predicting the losses associated with a transaction, it is possible to predict the power required at the delivery end of a line for meeting a certain portion of a retailer's future demand.

The learning coefficient can be kept updated, as and when new operational scenarios come up [15].

Loss in a transaction can be calculated using the following formula,

$$Loss_t = \frac{\alpha}{P_d} + \beta + \gamma P_d \tag{29}$$

where $Loss_t$ = the loss in a transaction

P_d = the total demand at the retailer's point in p.u.

α, β, γ = the learning coefficients

This equation represents a relationship between the transmission loss incurred while supplying a given load and the power demand. P_d is an independent variable while $Loss_t$ is a dependent variable. If P_d and $Loss_t$ are known for the past few scenarios, they can be used in equation (20) to obtain the coefficients α, β, γ. These coefficients can then be used to predict loss associated to any given transaction. This method is proposed in [16].

For example, if the past three scenarios are known, then the following formula may be used

$$\begin{bmatrix} \alpha \\ \beta \\ \gamma \end{bmatrix} = \begin{bmatrix} \dfrac{1}{P_{d1}} & 1 & P_{d1} \\ \dfrac{1}{P_{d2}} & 1 & P_{d1} \\ \dfrac{1}{P_{d3}} & 1 & P_{d1} \end{bmatrix}^{-1} \begin{bmatrix} Loss_{t1} \\ Loss_{t2} \\ Loss_{t3} \end{bmatrix} \tag{30}$$

then the determined coefficients can be used in equation (20) to predict the power loss in a transaction for an oncoming operating scenario. The predicted losses are supposed to match the losses obtained from a power flow. Using equation (22), we can then determine the percentage error to see is the predicted losses are valid. An error of 10% is acceptable [17].

$$\%Error = \left|\frac{Loss_{t4} - Loss_{t4pred}}{Loss_{t4}}\right| \times 100\% \qquad (31)$$

3.4 The IEEE 24-Bus RTS System

For this project, the IEEE 24-bus RTS system [18] will be used to do power flows and tracing and determine transmission losses. Figure 5 shows the diagram of the system that will be used in the project.

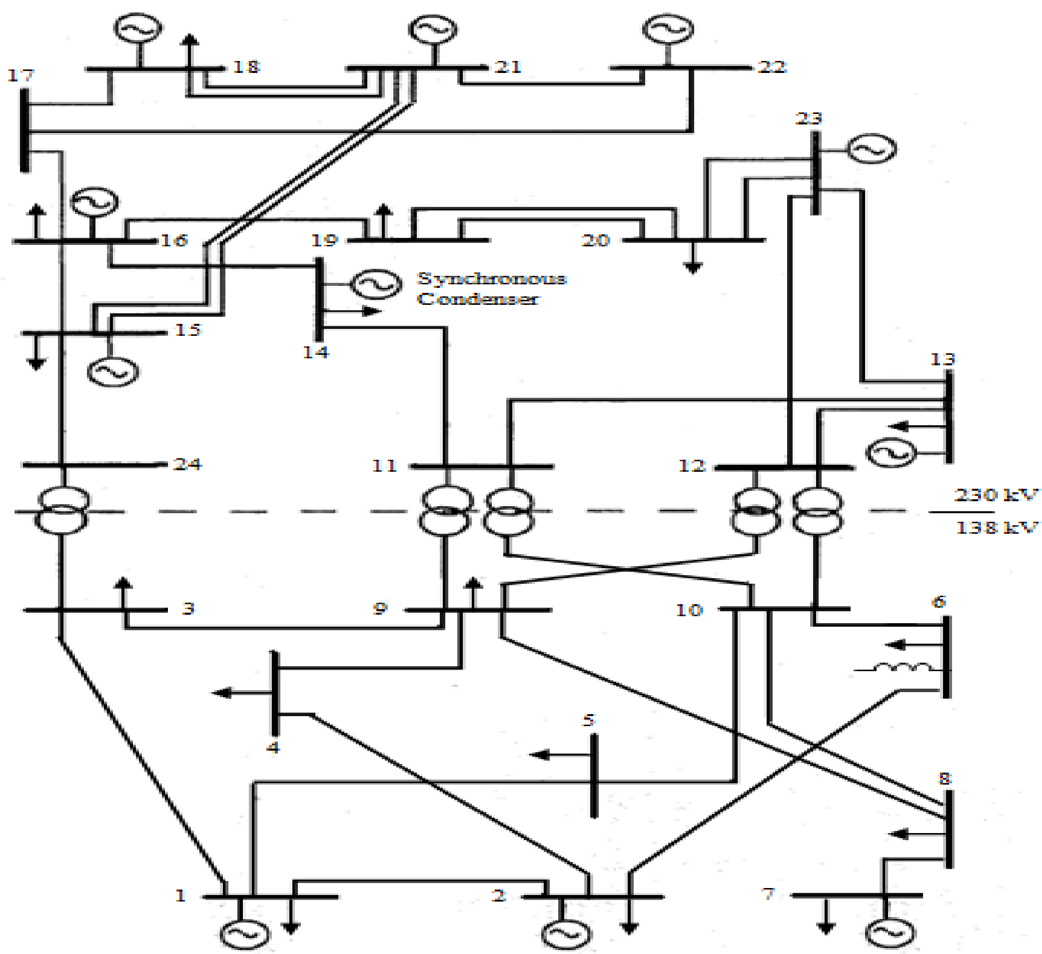

Figure 8: IEEE 24-bus RTS system

The bus load is assigned based on assumptions shown in table 1.

Table 1: IEEE 24-bus system bus data

Bus number	Bus load	Load		If peak is 10% higher	
	% system load	MW	MVar	MW	MVar
101	3.8	108	22	118.8	24.2
102	3.4	97	20	106.7	22
103	6.3	180	37	198	40.7
104	2.6	74	15	81.4	16.5
105	2.5	71	14	78.1	15.4
106	4.8	136	28	149.5	30.8
107	4.4	125	25	137.5	27.5
108	6	171	35	188.1	38.5
109	6.1	175	36	192.5	39.6
110	6.8	195	40	214.5	44
111	0	0	0	0	0
112	0	0	0	0	0
113	9.3	265	54	219.5	59.4
114	6.8	195	39	213.4	42.9
115	11.1	317	64	348.7	70.4
116	3.5	100	20	110	22
117	0	0	0	0	0
118	11.7	333	68	366.3	748
119	6.4	181	37	199.1	40.7
120	4.5	128	26	140.8	28.6
121	0	0	0	0	0
122	0	0	0	0	0
123	0	0	0	0	0
124	0	0	0	0	0

CHAPTER 4
RESULTS AND DISCUSSIONS

4.1 Power Flow Simulation

Appendix A and appendix B show power flow programs in m-file. These programs are used to run the power flow tracing of the system in figure 5. The bus data and generation data is specified in the m-file in appendix A, and the code used to do the power flow is specified in appendix B. Appendix C shows the results of the power flow, the load flow among the buses and the losses encountered. Matpower was used to run the simulation. The losses from the simulation are tabulated in table 2; the results simply show power losses between the buses after power tracing is done.

4.2 Solving Loss Allocation Algorithms

Appendix D shows the matlab code used to solve the loss allocation methods. The methods presented here are pro rata, ITL, proportional sharing and U-ITL algorithms. The results of the power flow from the 24 bus RTS are used to solve these algorithms. Table 6 shows the results of the 24 bus RTS power flow obtained by using matpower.

The loss allocation is performed for both the generation and demands. In section 3.3 of this report, the formulas of the loss allocation methods have been presented. These methods are used together with the system data in table 1 and the power flow results in table 2 to calculate the transmission losses. Table 3 and table 4 show the resulting losses obtained for the different methods.

Table 2: Power flow results

Branch	Bus		From Bus Injection		To Bus Injection		Loss(I^2*Z)	
#	From	To	P(MW)	Q(MVAr)	P(MW)	Q(MVAr)	P(MW)	Q(MVAr)
1	1	2	10.60	-26.67	-10.6	-22.70	0.003	0.02
2	1	3	-5.21	20.40	5.50	-25.12	0.29	1.14
3	1	5	58.60	5.17	-57.60	-4.48	0.71	2.74
4	2	4	38.01	19.14	-37.43	-20.46	0.58	2.23
5	2	6	47.60	-0.85	-46.54	-0.53	1.05	5.07
6	3	9	17.15	-15.26	-17.00	12.65	0.15	0.58
7	3	24	-202.65	3.39	203.68	33.91	1.02	37.3
8	4	9	-36.57	5.46	36.94	-6.82	0.37	1.44
9	5	10	-13.10	-9.16	13.15	6.85	0.05	0.2
10	6	10	-89.46	-129.95	90.54	-121.34	1.09	4.73
11	7	8	115.00	26.79	-112.88	-20.31	2.12	8.18
12	8	9	-36.57	3.12	37.17	-5.28	0.59	2.29
14	9	11	-106.49	-12.56	106.77	22.76	0.28	10.2
15	9	12	-125.62	-24.00	126.02	38.51	0.40	14.51
16	10	11	-150.16	35.61	150.70	-25.95	0.54	19.66
19	11	14	-161.26	46.26	162.83	-42.61	1.57	12.18
20	12	13	-62.32	-34.35	62.61	26.39	0.29	2.25
21	12	23	-234.75	-4.18	241.57	35.57	6.812	53.07
22	13	23	-232.54	7.46	238.34	18.26	5.80	45.2
25	15	21	-351.36	-6.04	358.92	53.90	7.56	58.83
26	15	24	206.63	45.96	-203.68	-33.91	2.96	22.89
27	16	17	-396.34	-14.11	401.36	47.73	5.02	39.37
28	16	19	130.53	-6.73	-130.04	5.53	0.49	3.81
30	17	22	-160.09	9.31	163.35	-7.90	3.27	25.5
31	18	21	-175.30	23.08	176.24	-21.71	0.94	7.38
32	19	20	-50.96	-42.53	51.16	35.37	0.20	1.56
33	20	23	-179.16	-61.37	180.10	63.65	0.94	7.21
34	21	22	-135.16	15.37	136.65	-19.51	1.48	11.57
						Total	51.246	454.77

Table 3 shows the losses allocated to the generators, and table 4 shows the losses allocated to the loads.

Table 3: Transmission losses allocated to generators

Bus no	Real power loss(MW)			
	PR	PS	ITL	U-ITL
1	1.5192	1.080	9.6556	16.8186
2	1.5192	1.6800	8.2394	15.4705
7	2.1198	2.1200	7.4980	17.7557
13	1.6539	5.4400	-8.6527	0.0000
15	1.899	9.3300	-7.5730	2.2606
16	1.369	3.7800	10.1251	16.5193
18	3.533	0.2200	21.4494	38.1571
21	3.533	2.0000	3.5928	21.1050
22	2.6497	0	3.5928	16.6890
23	5.8294	0	3.5928	32.5521

Table 4: Losses allocated to loads

Bus no	Real power losses(MW)			
	PR	PS	ITL	U-ITL
1	0.9711	0.5400	7.6667	1.3656
2	0.8721	0.8400	5.8759	2.3261
3	1.6184	0.6750	-4.5432	21.1511
4	0.6654	0.1850	-4.5432	11.6154
5	0.6384	0.0250	-4.5432	11.3458
6	1.2228	0.5350	-4.5432	17.1964
7	1.1239	1.0600	4.9383	5.8726
8	1.5375	0.4600	-4.5432	20.3545
9	1.5735	1.4050	-4.5432	20.7162
10	1.7533	0.5900	-4.5432	22.5098
13	2.3917	2.7200	-15.4850	40.7292
14	1.7443	3.5250	-4.5432	22.4155
15	2.8502	4.6650	-14.1197	43.9184
16	0.8991	1.8900	8.2604	0.0000
18	2.9941	0.1100	22.5806	5.3721
19	1.6274	0.1200	-4.5432	21.2489
20	1.1509	0.2900	-4.5432	16.4779
Total	46.23	45.29	25.8057	413.77

From table 4, we can notice that for pro rata (PR) and proportional sharing (PS), the losses are always positive, however, for incremental loss (ITL), there are negative losses. That is because for pro rata and proportional sharing, the losses allocated to the generators and loads are supposed to be positive all the time. And for ITL, the losses allocated can be negative. These negative losses can be interpreted as cross subsidies. The unsubsidized ITL (U-ITL) method eliminates the negative losses if they are undesirable.

The losses allocated to generators and demands in table 3 and table 4 is plotted to show and shown in figure 9 and figure 10 below.

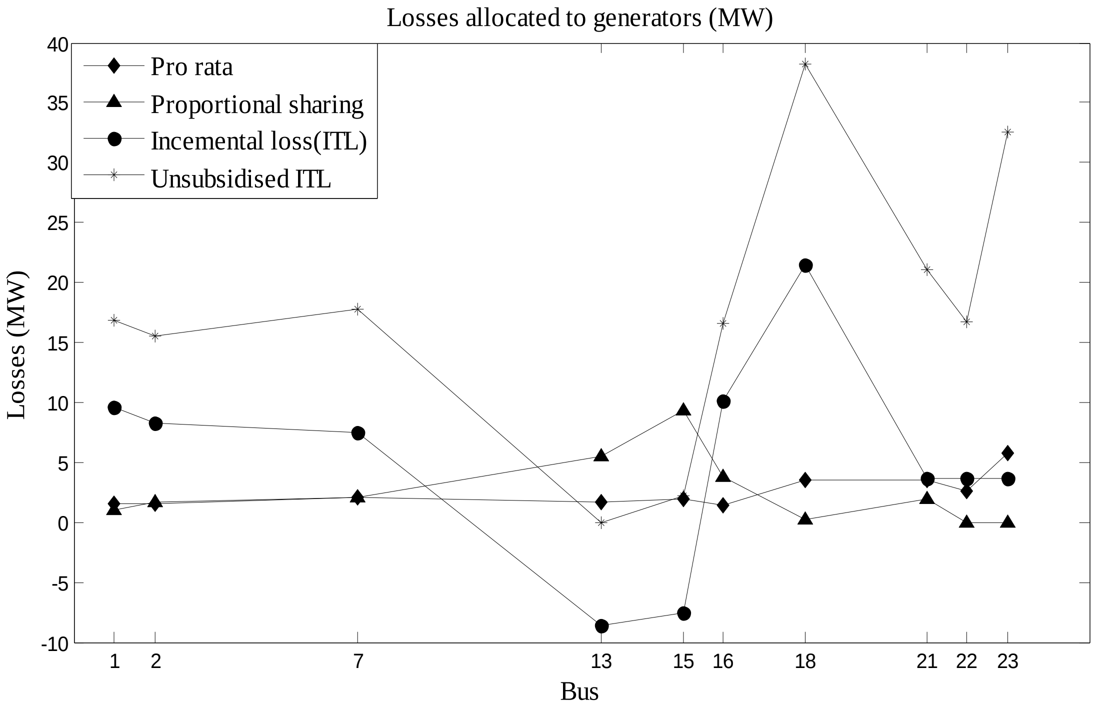

Figure 9: Losses allocated to generators

In figure 9 above, there are plots of the losses allocated to generators. From just observing, we can see that the losses obtained by using incremental loss method differs significantly from the ones obtained using pro rata and proportional sharing. This may be a result of the different ways in which the methods address the topological considerations of he network. The same applies for the plots of the losses allocated to loads in figure 10.

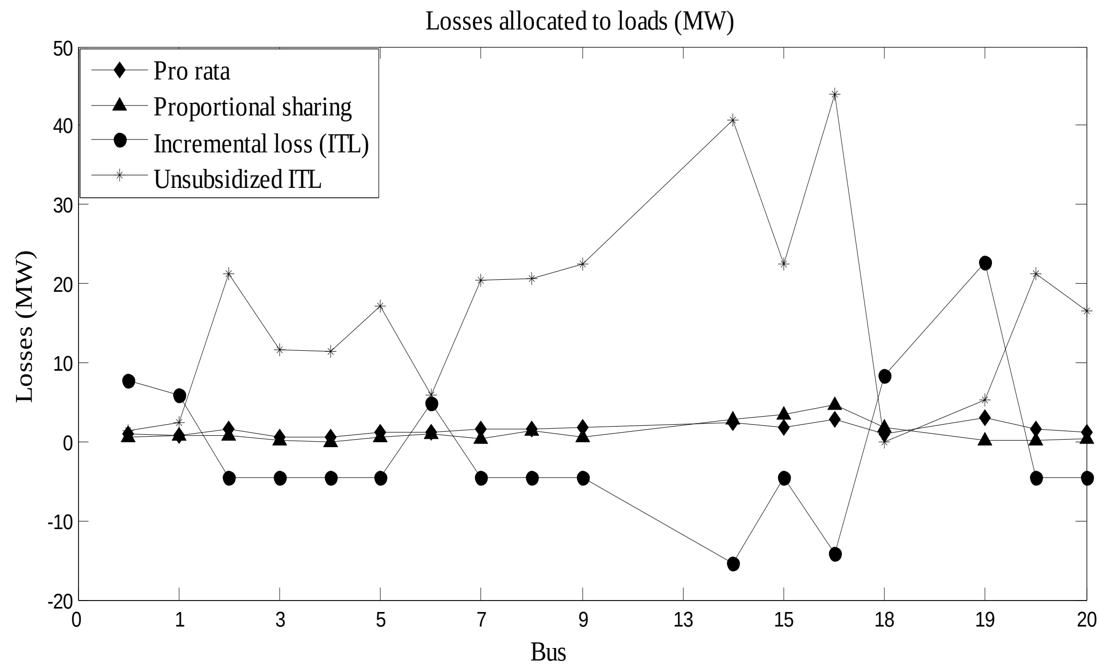

Figure 10: Losses allocated to loads

The four different methods were used to allocate the losses to each load and generator as the results are shown in figure 9 and 10. The ITL method produces some negative losses, even though other methods produce positive losses. This happens because ITL is highly dependent on choosing a slack generator bus.

The results for pro rata and proportional sharing methods are always different. This is because the pro rata method neglects the network and only depends on the level of power produced by generators or power consumed by loads. However, as seen in figure 9 and 10, the pattern for these two methods is almost similar. The main disadvantage of the pro rata method is that it is unfair to some participants even though they have good positioning in the market. For example, loads do no get financial incentives even though they are close to generators. This method is also unable to trace power flows.

The ITL and PS methods are also produce completely different results. This is because the ITL coefficients are chosen from changes of power injection at the selected bus while the slack generator bus either increases or decreases power automatically. The total allocation of the ITL is much different from the total real losses. To minimize this difference some normalization has to be performed on the method. This method fails to separate contributions of power between the selected bus and the slack bus generator.

The PS method is able to trace the contribution of losses caused by each generator and load. This method never allocates negative losses because it follows the direction of the power flow. The method uses an assumption to separate power flows from different sources, but the sum of the total allocation is consistent with the real total losses. As a result this method is more reasonable that other methods and can be easily understood by each participant.

The qualitative and quantitative measurements are used to determine which method is better. Table 5 shows the measurements.

Table 5: Qualitative and quantitative measurements

Characteristics	Methods			
	Prorata	PS	ITL	U_ITL
Consistent with a solved load flow	No	Yes	Yes	Yes
Only giving positive allocation	Yes	Yes	No	Yes
Not volatile	Yes	Yes	No	No
Able to trace the power in and out	No	Yes	No	No
The total sum of the allocations must be consistent to the real total losses	Yes	Yes	No	No

According to table 6, the PS method is the best of the four methods. This is because it can allocate the losses that have the total sum as the real losses and is therefore consistent with a solved power flow solution. Although this method uses assumption, this assumption has been proved in [19].

The pro rata method may be applied in a network where the loads and generators are close to one another, as it neglects the position of loads and generators in the network. This method is easy to understand and implement. Its pattern is similar to that of the PS method. It is by far the most popular method around the world.

The ITL method is not recommended because the allocation produces negative losses and the results are volatile depending on the choice of a slack generator bus. This method also needs a normalization procedure to match the total sum of the loss allocations to the real total losses.

The U-ITL method gets rid of the negative losses produces by the ITL method. But the method still needs normalization to match the total sum of the loss allocation to the real total losses.

4.3 Predicting Power Loss in a Transaction

Loss prediction was performed and tables 6-8 present the results. The past four scenarios were used to predict the fifth scenarios. These scenarios were created by continuously increasing the original demand by 10% and calculating the losses for each scenario. All this information was then combined and used to predict the losses for the fifth scenario.

Table 6 shows the original load, and how it is continuously increased by 10 %. Pd = load power; Pd1 = Pd increased by 10 %; Pd2 = Pd1 increased by 10 %; Pd3 = Pd2 increased by 10 %; Pd4 = Pd3 increased by 10 %.

Table 6: Load power with 10 % increments

Bus no	Pd (pu)	Pd1 (pu)	Pd2 (pu)	Pd3 (pu)	Pd4 (pu)
1	1.08	1.188	1.3068	1.4375	1.5812
2	0.97	1.067	1.1137	1.2911	1.4202
3	1.80	1.980	2.1780	2.3958	2.6354
4	0.74	0.814	0.8954	0.9849	1.0834
5	0.71	0.781	0.8591	0.9450	1.0395
6	1.36	1.496	1.6456	1.8102	1.9912
7	1.25	1.375	1.5125	1.6638	1.8301
8	1.71	1.881	2.0691	2.2760	2.5036
9	1.75	1.925	2.1175	2.3293	2.5622
10	1.95	2.145	2.3595	2.5955	2.8550
13	2.65	2.915	3.2065	3.5272	3.8799
14	1.94	2.134	2.3474	2.5822	2.8404
15	3.17	3.487	3.8357	4.2193	4.6412
16	1.00	1.100	1.2100	1.3310	1.4641
18	3.33	3.663	4.0293	4.4322	4.8754
19	1.81	1.991	2.1901	2.4091	2.6500
20	1.28	1.408	1.5488	1.7037	1.8740

Load flow is performed for all the scenarios in table 6 using matlab, and the corresponding losses are tabulated in table 7.

For table 7 below, LossT corresponds to Pd; LossT1 corresponds to Pd1; LossT2 corresponds to Pd2; LossT3 corresponds to Pd3; LossT4 corresponds to Pd4.

Table 7: Losses obtained by load flow corresponding to 10% increment

Bus no	LossT	LossT1	LossT2	LossT3	LossT4
1	0.01870	0.00989	0.00999	0.01224	0.01920
2	0.01680	0.01417	0.01270	0.01364	0.01994
3	0.01353	0.01205	0.01257	0.01593	0.02347
4	0.00364	0.00720	0.01229	0.02045	0.03350
5	0.00046	0.00164	0.00448	0.00950	0.02000
6	0.01670	0.01568	0.02261	0.03228	0.04629
7	0.02118	0.01798	0.01584	0.01589	0.02081
8	0.00907	0.01827	0.03391	0.05931	0.10109
9	0.00646	0.01046	0.01629	0.02475	0.03736
10	0.01187	0.01773	0.02588	0.03740	0.05430
13	0.05438	0.02826	0.00933	0.00133	0.01049
14	0.07054	0.06000	0.04952	0.03936	0.02984
15	0.09335	0.09096	0.08968	0.09024	0.09415
16	0.03786	0.03031	0.02392	0.01938	0.01786
18	0.00222	0.00254	0.00292	0.00336	0.00384
19	0.00226	0.00506	0.01066	0.02014	0.03538
20	0.00582	0.01038	0.01740	0.02776	0.04294

Now that we have relevant information for the past scenarios, the demands and their losses, we use then to calculate the learning coefficients. These coefficients can then be used predict any of the oncoming scenario.

With the information that has been acquired in table 6 table 7, the coefficients α, β and γ can now be calculated using equation (29).Table 8 shows the results of the calculation.

Table 8: Learning coefficients

Bus no	A	β	γ
1	0.1465	-0.2265	0.0952
2	0.1572	-0.2524	0.1118
3	0.3181	-0.2998	0.0764
4	0.1201	-0.3254	0.2273
5	0.0853	-0.2353	0.1635
6	0.1764	-0.2788	0.1180
7	0.1905	-0.2251	0.0760
8	0.8883	-1.0397	0.3114
9	0.2270	-0.2730	0.0860
10	0.3158	-0.3448	0.1004
13	2.1537	-1.930	0.1655
14	0.1682	0.0143	-0.0155
15	0.3954	-0.1127	0.0259
16	0.1578	-0.1796	0.0604
18	0.0046	-0.0037	0.0014
19	0.3809	-0.4161	0.1155
20	0.2140	-0.3500	0.1480

Since now we have α, β and γ, we can predict the losses if the load in table 6 is increased by another 10 %, i.e. losses when the load power is Pd4. Equation (30) is used for the prediction and the results are tabulated in table 9.

Percentage error can be calculated to see how accurate the predication is. Equation (31) is used to calculate the error. The acceptable error is within 10%.

Table 9: Losst4pred for Pd4 compared with Losst4 from load flow

Bus no	LossT4(pu)	LossT4pred(pu)	Percentage Error (%)
1	0.01920	0.0167	13.02
2	0.01994	0.0170	14.7
3	0.02347	0.0222	5.4
4	0.03350	0.0318	5.1
5	0.02000	0.0167	16.5
6	0.04629	0.0448	3.2
7	0.02081	0.0181	13.02
8	0.10109	0.0947	6.3
9	0.03736	0.0359	3.91
10	0.05430	0.0524	3.40
13	0.01049	0.0042	59.96
14	0.02984	0.0294	1.47
15	0.09415	0.0926	1.65
16	0.01786	0.0166	7.05
18	0.00384	0.0039	1.56
19	0.03538	0.0336	5.03
20	0.04294	0.0416	3.12

As the results can be seen, the losses have been predicted successfully, as most of the values fall within the acceptable 10% error. Even the values that fall outside the 10% don’t are still close to the range. Only one prediction is done totally unsuccessfully, so we can safely conclude that this method is suitable to be used for loss prediction.

CHAPTER 5
CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

A 24 bus RTS was used for simulation to obtain the power flow. The results of the power flow were then used together with the loss allocation algorithms in section 3.3 of the report to allocate the losses to generators and loads using pro rata, proportional sharing and incremental loss methods. These results were tabulated and plotted and the results were explained in chapter 4.

By far the pro rata is the most popular method, even though it neglects networks and it is not able to trace power flows. It is unfair to certain market participants.

The ITL method produces volatile results and negative losses. It also needs to be normalized in order to give the total sum of allocations that is consistent with the real total losses.

The U-ITL gets rid of the negative losses produced by the ITL method, but still needs to be normalized in order to give the total sum of allocations that is the same as the real total losses.

The PS method is the most reasonable of the four methods. It is able to trace the flow of power in and out at each bus, from generators and loads vice versa. This method is also able to trace the contributions of losses caused by each load or generator. The results of this method are always positive and the total sum of loss allocations is consistent with the total sum of the real losses.

Lastly loss prediction was performed was done and the results were satisfactory. The adopted method for prediction proved to be reliable as the predicted values were close enough to those acquired using load flow.

5.2 Recommendations

To take the research a little further, the study can be focus on the weekly power consumption of a certain area (for example place of residence). Allocation and prediction can then be done on the weekly power generation, demand and losses. The actual power can then be obtained and compared with the predicted power to see if the prediction was successful.

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APPENDICES

APPENDIX A

M-FILE SPECIFYING SYTEM DATA

```
function mpc = case24_ieee_rts
mpc.version = '2';

%%-----  Power Flow Data  -----%%
%% system MVA base
mpc.baseMVA = 100;

%% bus data
%   bus_i   type    Pd  Qd  Gs  Bs  area    Vm  Va  baseKV  zone    Vmax
Vmin
mpc.bus = [
    1   2   108 22  0   0   1   1   0   138 1   1.05    0.95;
    2   2   97  20  0   0   1   1   0   138 1   1.05    0.95;
    3   1   180 37  0   0   1   1   0   138 1   1.05    0.95;
    4   1   74  15  0   0   1   1   0   138 1   1.05    0.95;
    5   1   71  14  0   0   1   1   0   138 1   1.05    0.95;
    6   1   136 28  0   -100    2   1   0   138 1   1.05    0.95;
    7   2   125 25  0   0   2   1   0   138 1   1.05    0.95;
    8   1   171 35  0   0   2   1   0   138 1   1.05    0.95;
    9   1   175 36  0   0   1   1   0   138 1   1.05    0.95;
    10  1   195 40  0   0   2   1   0   138 1   1.05    0.95;
    11  1   0   0   0   0   3   1   0   230 1   1.05    0.95;
    12  1   0   0   0   0   3   1   0   230 1   1.05    0.95;
    13  3   265 54  0   0   3   1   0   230 1   1.05    0.95;
    14  2   194 39  0   0   3   1   0   230 1   1.05    0.95;
    15  2   317 64  0   0   4   1   0   230 1   1.05    0.95;
    16  2   100 20  0   0   4   1   0   230 1   1.05    0.95;
    17  1   0   0   0   0   4   1   0   230 1   1.05    0.95;
    18  2   333 68  0   0   4   1   0   230 1   1.05    0.95;
    19  1   181 37  0   0   3   1   0   230 1   1.05    0.95;
    20  1   128 26  0   0   3   1   0   230 1   1.05    0.95;
    21  2   0   0   0   0   4   1   0   230 1   1.05    0.95;
    22  2   0   0   0   0   4   1   0   230 1   1.05    0.95;
    23  2   0   0   0   0   3   1   0   230 1   1.05    0.95;
    24  1   0   0   0   0   4   1   0   230 1   1.05    0.95;
];

%% generator data
%   bus Pg  Qg  Qmax    Qmin    Vg  mBase   status  Pmax    Pmin    Pc1
Pc2 Qc1min  Qc1max  Qc2min  Qc2max  ramp_agc    ramp_10 ramp_30 ramp_q
apf %   Unit Code
mpc.gen = [
    1   10  0   10  0   1.035   100 1   20  16  0   0   0   0   0   0
0   0   0   0   0;  %   U20
    1   10  0   10  0   1.035   100 1   20  16  0   0   0   0   0   0
0   0   0   0   0;  %   U20
    1   76  0   30  -25 1.035   100 1   76  15.2    0   0   0   0   0
0   0   0   0   0   0;  %   U76
    1   76  0   30  -25 1.035   100 1   76  15.2    0   0   0   0   0
0   0   0   0   0   0;  %   U76
    2   10  0   10  0   1.035   100 1   20  16  0   0   0   0   0   0
0   0   0   0   0;  %   U20
    2   10  0   10  0   1.035   100 1   20  16  0   0   0   0   0   0
0   0   0   0   0;  %   U20
    2   76  0   30  -25 1.035   100 1   76  15.2    0   0   0   0   0
0   0   0   0   0   0;  %   U76
```

```
	2	76	0	30	-25 1.035	100 1	76	15.2	0	0	0	0	0
0	0	0	0	0	0;	%	U76
	7	80	0	60	0	1.025	100 1	100 25	0	0	0	0	0	0
0	0	0	0	0;	%	U100
	7	80	0	60	0	1.025	100 1	100 25	0	0	0	0	0	0
0	0	0	0	0;	%	U100
	7	80	0	60	0	1.025	100 1	100 25	0	0	0	0	0	0
0	0	0	0	0;	%	U100
	13	95.1	0	80	0	1.02	100 1	197 69	0	0	0	0	0
0	0	0	0	0	0;	%	U197
	13	95.1	0	80	0	1.02	100 1	197 69	0	0	0	0	0
0	0	0	0	0	0;	%	U197
	13	95.1	0	80	0	1.02	100 1	197 69	0	0	0	0	0
0	0	0	0	0	0;	%	U197
	14	0	35.3	200 -50 0.98	100 1	0	0	0	0	0	0	0
0	0	0	0	0	0;	%	SynCond
	15	12	0	6	0	1.014	100 1	12	2.4 0	0	0	0	0	0
0	0	0	0	0;	%	U12
	15	12	0	6	0	1.014	100 1	12	2.4 0	0	0	0	0	0
0	0	0	0	0;	%	U12
	15	12	0	6	0	1.014	100 1	12	2.4 0	0	0	0	0	0
0	0	0	0	0;	%	U12
	15	12	0	6	0	1.014	100 1	12	2.4 0	0	0	0	0	0
0	0	0	0	0;	%	U12
	15	12	0	6	0	1.014	100 1	12	2.4 0	0	0	0	0	0
0	0	0	0	0;	%	U12
	15	155 0	80	-50 1.014	100 1	155 54.3	0	0	0	0	0
0	0	0	0	0	0;	%	U155
	16	155 0	80	-50 1.017	100 1	155 54.3	0	0	0	0	0
0	0	0	0	0	0;	%	U155
	18	400 0	200 -50 1.05	100 1	400 100 0	0	0	0	0	0
0	0	0	0	0;	%	U400
	21	400 0	200 -50 1.05	100 1	400 100 0	0	0	0	0	0
0	0	0	0	0;	%	U400
	22	50	0	16	-10 1.05	100 1	50	10	0	0	0	0	0	0
0	0	0	0	0;	%	U50
	22	50	0	16	-10 1.05	100 1	50	10	0	0	0	0	0	0
0	0	0	0	0;	%	U50
	22	50	0	16	-10 1.05	100 1	50	10	0	0	0	0	0	0
0	0	0	0	0;	%	U50
	22	50	0	16	-10 1.05	100 1	50	10	0	0	0	0	0	0
0	0	0	0	0;	%	U50
	22	50	0	16	-10 1.05	100 1	50	10	0	0	0	0	0	0
0	0	0	0	0;	%	U50
	22	50	0	16	-10 1.05	100 1	50	10	0	0	0	0	0	0
0	0	0	0	0;	%	U50
	23	155 0	80	-50 1.05	100 1	155 54.3	0	0	0	0	0
0	0	0	0	0	0;	%	U155
	23	155 0	80	-50 1.05	100 1	155 54.3	0	0	0	0	0
0	0	0	0	0	0;	%	U155
	23	350 0	150 -25 1.05	100 1	350 140 0	0	0	0	0	0
0	0	0	0	0;	%	U350
];

%% branch data
%	fbus	tbus	r	x	b	rateA	rateB	rateC	ratio	angle
status	angmin	angmax
mpc.branch = [
	1	2	0.0026	0.0139	0.4611	175 250 200 0	0	1	-360	360;
	1	3	0.0546	0.2112	0.0572	175 208 220 0	0	1	-360	360;
	1	5	0.0218	0.0845	0.0229	175 208 220 0	0	1	-360	360;
	2	4	0.0328	0.1267	0.0343	175 208 220 0	0	1	-360	360;
	2	6	0.0497	0.192	0.052	175 208 220 0	0	1	-360	360;
	3	9	0.0308	0.119	0.0322	175 208 220 0	0	1	-360	360;
```

```
    3   24  0.0023  0.0839  0   400 510 600 1.03    0   1   -360    360;
    4   9   0.0268  0.1037  0.0281  175 208 220 0   0   1   -360    360;
    5   10  0.0228  0.0883  0.0239  175 208 220 0   0   1   -360    360;
    6   10  0.0139  0.0605  2.459   175 193 200 0   0   1   -360    360;
    7   8   0.0159  0.0614  0.0166  175 208 220 0   0   1   -360    360;
    8   9   0.0427  0.1651  0.0447  175 208 220 0   0   1   -360    360;
    8   10  0.0427  0.1651  0.0447  175 208 220 0   0   1   -360    360;
    9   11  0.0023  0.0839  0   400 510 600 1.03    0   1   -360    360;
    9   12  0.0023  0.0839  0   400 510 600 1.03    0   1   -360    360;
    10  11  0.0023  0.0839  0   400 510 600 1.02    0   1   -360    360;
    10  12  0.0023  0.0839  0   400 510 600 1.02    0   1   -360    360;
    11  13  0.0061  0.0476  0.0999  500 600 625 0   0   1   -360    360;
    11  14  0.0054  0.0418  0.0879  500 625 625 0   0   1   -360    360;
    12  13  0.0061  0.0476  0.0999  500 625 625 0   0   1   -360    360;
    12  23  0.0124  0.0966  0.203   500 625 625 0   0   1   -360    360;
    13  23  0.0111  0.0865  0.1818  500 625 625 0   0   1   -360    360;
    14  16  0.005   0.0389  0.0818  500 625 625 0   0   1   -360    360;
    15  16  0.0022  0.0173  0.0364  500 600 625 0   0   1   -360    360;
    15  21  0.0063  0.049   0.103   500 600 625 0   0   1   -360    360;
    15  21  0.0063  0.049   0.103   500 600 625 0   0   1   -360    360;
    15  24  0.0067  0.0519  0.1091  500 600 625 0   0   1   -360    360;
    16  17  0.0033  0.0259  0.0545  500 600 625 0   0   1   -360    360;
    16  19  0.003   0.0231  0.0485  500 600 625 0   0   1   -360    360;
    17  18  0.0018  0.0144  0.0303  500 600 625 0   0   1   -360    360;
    17  22  0.0135  0.1053  0.2212  500 600 625 0   0   1   -360    360;
    18  21  0.0033  0.0259  0.0545  500 600 625 0   0   1   -360    360;
    18  21  0.0033  0.0259  0.0545  500 600 625 0   0   1   -360    360;
    19  20  0.0051  0.0396  0.0833  500 600 625 0   0   1   -360    360;
    19  20  0.0051  0.0396  0.0833  500 600 625 0   0   1   -360    360;
    20  23  0.0028  0.0216  0.0455  500 600 625 0   0   1   -360    360;
    20  23  0.0028  0.0216  0.0455  500 600 625 0   0   1   -360    360;
    21  22  0.0087  0.0678  0.1424  500 600 625 0   0   1   -360    360;
];

%%-----  OPF Data  -----%%
%% area data
%   area    refbus
mpc.areas = [
    1   1;
    2   3;
    3   8;
    4   6;
];

%% generator cost data
%   1   startup shutdown    n   x1  y1  ... xn  yn
%   2   startup shutdown    n   c(n-1)  ... c0
mpc.gencost = [                                 %   bus Pmin    Pmax    Qmin
Qmax    Unit Code
    2   1500    0   3   0   130 400.6849;   %   1   16  20  0   10  U20
    2   1500    0   3   0   130 400.6849;   %   1   16  20  0   10  U20
    2   1500    0   3   0.014142    16.0811 212.3076;   %   1   15.2
76  -25 30  U76
    2   1500    0   3   0.014142    16.0811 212.3076;   %   1   15.2
76  -25 30  U76
    2   1500    0   3   0   130 400.6849;   %   2   16  20  0   10  U20
    2   1500    0   3   0   130 400.6849;   %   2   16  20  0   10  U20
    2   1500    0   3   0.014142    16.0811 212.3076;   %   2   15.2
76  -25 30  U76
    2   1500    0   3   0.014142    16.0811 212.3076;   %   2   15.2
76  -25 30  U76
    2   1500    0   3   0.052672    43.6615 781.521;    %   7   25  100
0   60  U100
```

```
    2   1500     0   3   0.052672    43.6615 781.521;    %   7   25  100
0   60  U100
    2   1500     0   3   0.052672    43.6615 781.521;    %   7   25  100
0   60  U100
    2   1500     0   3   0.00717 48.5804 832.7575;   %   13  69  197 0
80  U197
    2   1500     0   3   0.00717 48.5804 832.7575;   %   13  69  197 0
80  U197
    2   1500     0   3   0.00717 48.5804 832.7575;   %   13  69  197 0
80  U197
    2   1500    0   3   0   0   0;  %   14                  SynCond
    2   1500     0   3   0.328412    56.564  86.3852;    %   15  2.4 12
0   6   U12
    2   1500     0   3   0.328412    56.564  86.3852;    %   15  2.4 12
0   6   U12
    2   1500     0   3   0.328412    56.564  86.3852;    %   15  2.4 12
0   6   U12
    2   1500     0   3   0.328412    56.564  86.3852;    %   15  2.4 12
0   6   U12
    2   1500     0   3   0.328412    56.564  86.3852;    %   15  2.4 12
0   6   U12
    2   1500     0   3   0.008342    12.3883 382.2391;   %   15  54.3
155 -50 80  U155
    2   1500     0   3   0.008342    12.3883 382.2391;   %   16  54.3
155 -50 80  U155
    2   1500     0   3   0.000213    4.4231  395.3749;   %   18  100 400
-50 200 U400
    2   1500     0   3   0.000213    4.4231  395.3749;   %   21  100 400
-50 200 U400
    2   1500    0   3   0   0.001   0.001;  %   22  10  50  -10 16  U50
    2   1500    0   3   0   0.001   0.001;  %   22  10  50  -10 16  U50
    2   1500    0   3   0   0.001   0.001;  %   22  10  50  -10 16  U50
    2   1500    0   3   0   0.001   0.001;  %   22  10  50  -10 16  U50
    2   1500    0   3   0   0.001   0.001;  %   22  10  50  -10 16  U50
    2   1500    0   3   0   0.001   0.001;  %   22  10  50  -10 16  U50
    2   1500     0   3   0.008342    12.3883 382.2391;   %   23  54.3
155 -50 80  U155
    2   1500     0   3   0.008342    12.3883 382.2391;   %   23  54.3
155 -50 80  U155
    2   1500     0   3   0.004895    11.8495 665.1094;   %   23  140 350
-25 150 U350
];
```

APPENDIX B

POWER FLOW PRORAM

```
function [MVAbase, bus, gen, branch, success, et] = ...
                runpf(casedata, mpopt, fname, solvedcase)
 [PQ, PV, REF, NONE, BUS_I, BUS_TYPE, PD, QD, GS, BS, BUS_AREA, VM, ...
    VA,  BASE_KV,  ZONE,  VMAX,  VMIN,  LAM_P,  LAM_Q,  MU_VMAX,  MU_VMIN]  =
idx_bus;
[F_BUS, T_BUS, BR_R, BR_X, BR_B, RATE_A, RATE_B, RATE_C, ...
    TAP, SHIFT, BR_STATUS, PF, QF, PT, QT, MU_SF, MU_ST, ...
    ANGMIN, ANGMAX, MU_ANGMIN, MU_ANGMAX] = idx_brch;
[GEN_BUS, PG, QG, QMAX, QMIN, VG, MBASE, GEN_STATUS, PMAX, PMIN, ...
    MU_PMAX, MU_PMIN, MU_QMAX, MU_QMIN, PC1, PC2, QC1MIN, QC1MAX, ...
    QC2MIN, QC2MAX, RAMP_AGC, RAMP_10, RAMP_30, RAMP_Q, APF] = idx_gen;

%% default arguments
if nargin < 4
    solvedcase = '';                %% don't save solved case
    if nargin < 3
        fname = '';                 %% don't print results to a file
        if nargin < 2
            mpopt = mpoption;       %% use default options
            if nargin < 1
                casedata = 'case9'; %% default data file is 'case9.m'
            end
        end
    end
end

%% options
verbose = mpopt(31);
qlim = mpopt(6);                    %% enforce Q limits on gens?
dc = mpopt(10);                     %% use DC formulation?

%% read data
mpc = loadcase(casedata);

%% add zero columns to branch for flows if needed
if size(mpc.branch,2) < QT
  mpc.branch    =    [    mpc.branch    zeros(size(mpc.branch,    1),    QT-
size(mpc.branch,2)) ];
end

%% convert to internal indexing
mpc = ext2int(mpc);
[baseMVA,   bus,   gen,   branch]   =   deal(mpc.baseMVA,   mpc.bus,   mpc.gen,
mpc.branch);

%% get bus index lists of each type of bus
[ref, pv, pq] = bustypes(bus, gen);

%% generator info
on = find(gen(:, GEN_STATUS) > 0);      %% which generators are on?
gbus = gen(on, GEN_BUS);                %% what buses are they at?

%%-----  run the power flow  -----
t0 = clock;
if verbose > 0
    v = mpver('all');
    fprintf('\nMATPOWER Version %s, %s', v.Version, v.Date);
end
```

```
if dc                               %% DC formulation
    if verbose > 0
      fprintf(' -- DC Power Flow\n');
    end
    %% initial state
    Va0 = bus(:, VA) * (pi/180);

    %% build B matrices and phase shift injections
    [B, Bf, Pbusinj, Pfinj] = makeBdc(baseMVA, bus, branch);

    %% compute complex bus power injections (generation - load)
    %% adjusted for phase shifters and real shunts
    Pbus  =  real(makeSbus(baseMVA,  bus,  gen))  -  Pbusinj  -  bus(:,  GS)  /
baseMVA;

    %% "run" the power flow
    Va = dcpf(B, Pbus, Va0, ref, pv, pq);

    %% update data matrices with solution
    branch(:, [QF, QT]) = zeros(size(branch, 1), 2);
    branch(:, PF) = (Bf * Va + Pfinj) * baseMVA;
    branch(:, PT) = -branch(:, PF);
    bus(:, VM) = ones(size(bus, 1), 1);
    bus(:, VA) = Va * (180/pi);
    %%  update  Pg  for  swing  generator  (note:  other  gens  at  ref  bus  are
accounted for in Pbus)
    %%      Pg = Pinj + Pload + Gs
    %%      newPg = oldPg + newPinj - oldPinj
    refgen  =  find(gbus  ==  ref);                   %%  which  is(are)  the
reference gen(s)?
    gen(on(refgen(1)),  PG)  =  gen(on(refgen(1)),  PG)  +  (B(ref,  :)  *  Va  -
Pbus(ref)) * baseMVA;

    success = 1;
else                                %% AC formulation
    if verbose > 0
      fprintf('  --  AC  Power  Flow  ');      %%  solver  name  and  \n  added
later
    end
    %% initial state
    % V0    = ones(size(bus, 1), 1);            %% flat start
    V0  = bus(:, VM) .* exp(sqrt(-1) * pi/180 * bus(:, VA));
    V0(gbus) = gen(on, VG) ./ abs(V0(gbus)).* V0(gbus);

    if qlim
        ref0 = ref;                         %% save index and angle of
        Varef0 = bus(ref0, VA);             %%   original reference bus
        limited = [];                        %% list of indices of gens @
Q lims
        fixedQg = zeros(size(gen, 1), 1);   %% Qg of gens at Q limits
    end
    repeat = 1;
    while (repeat)
        %% build admittance matrices
        [Ybus, Yf, Yt] = makeYbus(baseMVA, bus, branch);

        %% compute complex bus power injections (generation - load)
        Sbus = makeSbus(baseMVA, bus, gen);

        %% run the power flow
        alg = mpopt(1);
        if alg == 1
            [V,  success,  iterations]  =  newtonpf(Ybus,  Sbus,  V0,  ref,  pv,
pq, mpopt);
```

```
        elseif alg == 2 || alg == 3
            [Bp, Bpp] = makeB(baseMVA, bus, branch, alg);
            [V, success, iterations] = fdpf(Ybus, Sbus, V0, Bp, Bpp,
ref, pv, pq, mpopt);
        elseif alg == 4
            [V, success, iterations] = gausspf(Ybus, Sbus, V0, ref, pv,
pq, mpopt);
        else
            error('Only Newton''s method, fast-decoupled, and Gauss-
Seidel power flow algorithms currently implemented.');
        end

        %% update data matrices with solution
        [bus, gen, branch] = pfsoln(baseMVA, bus, gen, branch, Ybus, Yf,
Yt, V, ref, pv, pq);

        if qlim             %% enforce generator Q limits
            %% find gens with violated Q constraints
            mx = find( gen(:, GEN_STATUS) > 0 & gen(:, QG) > gen(:,
QMAX) );
            mn = find( gen(:, GEN_STATUS) > 0 & gen(:, QG) < gen(:,
QMIN) );

            if ~isempty(mx) || ~isempty(mn)  %% we have some Q limit
violations
                if isempty(pv)
                    if verbose
                        if ~isempty(mx)
                            fprintf('Gen %d (only one left) exceeds
upper Q limit : INFEASIBLE PROBLEM\n', mx);
                        else
                            fprintf('Gen %d (only one left) exceeds
lower Q limit : INFEASIBLE PROBLEM\n', mn);
                        end
                    end
                    success = 0;
                    break;
                end

                %% one at a time?
                if qlim == 2    %% fix largest violation, ignore the
rest
                    [junk, k] = max([gen(mx, QG) - gen(mx, QMAX);
                                     gen(mn, QMIN) - gen(mn, QG)]);
                    if k > length(mx)
                        mn = mn(k-length(mx));
                        mx = [];
                    else
                        mx = mx(k);
                        mn = [];
                    end
                end

                if verbose && ~isempty(mx)
                    fprintf('Gen %d at upper Q limit, converting to PQ
bus\n', mx);
                end
                if verbose && ~isempty(mn)
                    fprintf('Gen %d at lower Q limit, converting to PQ
bus\n', mn);
                end

                %% save corresponding limit values
                fixedQg(mx) = gen(mx, QMAX);
```

```
                fixedQg(mn) = gen(mn, QMIN);
                mx = [mx;mn];

                %% convert to PQ bus
                gen(mx, QG) = fixedQg(mx);         %% set Qg to binding
limit
                gen(mx, GEN_STATUS) = 0;          %% temporarily turn off
gen,
                for i = 1:length(mx)             %% (one at a time, since
                    bi = gen(mx(i), GEN_BUS);    %%  they may be at same
bus)
                    bus(bi, [PD,QD]) = ...              %%  adjust  load
accordingly,
                        bus(bi, [PD,QD]) - gen(mx(i), [PG,QG]);
                end
                bus(gen(mx, GEN_BUS), BUS_TYPE) = PQ;     %% & set bus
type to PQ

                %% update bus index lists of each type of bus
                ref_temp = ref;
                [ref, pv, pq] = bustypes(bus, gen);
                if verbose && ref ~= ref_temp
                    fprintf('Bus %d is new slack bus\n', ref);
                end
                limited = [limited; mx];
            else
                repeat = 0; %% no more generator Q limits violated
            end
        else
            repeat = 0;     %% don't enforce generator Q limits, once is
enough
        end
    end
    if qlim && ~isempty(limited)
        %% restore injections from limited gens (those at Q limits)
        gen(limited, QG) = fixedQg(limited);    %% restore Qg value,
        for i = 1:length(limited)               %% (one at a time, since
            bi = gen(limited(i), GEN_BUS);       %%  they may be at same
bus)
            bus(bi, [PD,QD]) = ...              %% re-adjust load,
                bus(bi, [PD,QD]) + gen(limited(i), [PG,QG]);
        end
        gen(limited, GEN_STATUS) = 1;               %% and turn gen back
on
        if ref ~= ref0
            %% adjust voltage angles to make original ref bus correct
            bus(:, VA) = bus(:, VA) - bus(ref0, VA) + Varef0;
        end
    end
end
mpc.et = etime(clock, t0);
mpc.success = success;

%%-----  output results  -----
%% convert back to original bus numbering & print results
[mpc.bus, mpc.gen, mpc.branch] = deal(bus, gen, branch);
results = int2ext(mpc);

%% zero out result fields of out-of-service gens & branches
if ~isempty(results.order.gen.status.off)
  results.gen(results.order.gen.status.off, [PG QG]) = 0;
end
if ~isempty(results.order.branch.status.off)
  results.branch(results.order.branch.status.off, [PF QF PT QT]) = 0;
```

```
end

if fname
    [fd, msg] = fopen(fname, 'at');
    if fd == -1
        error(msg);
    else
        printpf(results, fd, mpopt);
        fclose(fd);
    end
end
printpf(results, 1, mpopt);

%% save solved case
if solvedcase
    savecase(solvedcase, results);
end

if nargout == 1 || nargout == 2
    MVAbase = results;
    bus = success;
elseif nargout > 2
    [MVAbase, bus, gen, branch, et] = ...
        deal(results.baseMVA, results.bus, results.gen, results.branch,
results.et);
% else  %% don't define MVAbase, so it doesn't print anything
end
```

APPENDIX C-1

POWER FLOW SIMULATION RESULTS FOR ORIGINAL LOAD (PD)

```
Newton's method power flow converged in 4 iterations.

Converged in 0.53 seconds
================================================================================
|     System Summary                                                           |
================================================================================

How many?                How much?              P (MW)            Q (MVAr)
---------------------    -------------------  -------------  -----------------
Buses              24     Total Gen Capacity    3405.0        -535.0 to 1776.0
Generators         33     On-line Capacity      3405.0        -535.0 to 1776.0
Committed Gens     33     Generation (actual)   2901.2            587.4
Loads              17     Load                  2850.0            580.0
 Fixed             17      Fixed                2850.0            580.0
Dispatchable       0      Dispatchable            0.0 of 0.0        0.0
Shunts              1     Shunt (inj)              0.0           -102.5
Branches           38     Losses (I^2 * Z)        51.25           454.77
Transformers        5     Branch Charging (inj)     -             549.9
Inter-ties         10     Total Inter-tie Flow  1339.8            204.9
Areas               4

                          Minimum                      Maximum
                 -------------------------  --------------------------------
Voltage Magnitude   0.978 p.u. @ bus 24         1.050 p.u. @ bus 21
Voltage Angle     -12.42 deg   @ bus 6         22.77 deg   @ bus 22
P Losses (I^2*R)             -                  7.05 MW    @ line 14-16
Q Losses (I^2*X)             -                 54.88 MVAr  @ line 14-16
```

==
========
| Bus Data
|
==
========

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
1	1.035	-7.278	172.00	21.47	108.00	22.00
2	1.035	-7.370	172.00	15.66	97.00	20.00
3	0.989	-5.584	-	-	180.00	37.00
4	0.998	-9.690	-	-	74.00	15.00
5	1.019	-9.964	-	-	71.00	14.00
6	1.012	-12.421	-	-	136.00	28.00
7	1.025	-7.357	240.00	51.84	125.00	25.00
8	0.993	-11.088	-	-	171.00	35.00
9	1.001	-7.435	-	-	175.00	36.00
10	1.028	-9.503	-	-	195.00	40.00
11	0.990	-2.154	-	-	-	-
12	1.003	-1.517	-	-	-	-
13	1.020	0.000	187.25	133.99	265.00	54.00
14	0.980	2.258	0.00	-27.72	194.00	39.00
15	1.014	11.566	215.00	-3.95	317.00	64.00
16	1.017	10.449	155.00	44.40	100.00	20.00
17	1.039	14.931	-	-	-	-
18	1.050	16.292	400.00	138.73	333.00	68.00
19	1.023	8.917	-	-	181.00	37.00
20	1.038	9.530	-	-	128.00	26.00
21	1.050	17.117	400.00	106.91	-	-
22	1.050	22.766	300.00	-29.55	-	-
23	1.050	10.572	660.00	135.59	-	-
24	0.978	5.299	-	-	-	-
		Total:	2901.25	587.36	2850.00	580.00

==
========
| Branch Data
|
==
========

Brnch #	From Bus	To Bus	From Bus Injection P (MW)	From Bus Injection Q (MVAr)	To Bus Injection P (MW)	To Bus Injection Q (MVAr)	Loss (I^2 * Z) P (MW)	Loss (I^2 * Z) Q (MVAr)
1	1	2	11.94	-26.92	-11.94	-22.45	0.004	0.02
2	1	3	-7.97	21.57	8.31	-26.11	0.342	1.32
3	1	5	60.03	4.83	-59.29	-4.37	0.741	2.87
4	2	4	38.44	19.15	-37.85	-20.43	0.587	2.27
5	2	6	48.50	-1.04	-47.41	-0.19	1.093	4.22
6	3	9	22.90	-17.01	-22.66	14.75	0.240	0.93
7	3	24	-211.21	6.12	212.32	34.48	1.113	40.60
8	4	9	-36.15	5.43	36.52	-6.83	0.364	1.41
9	5	10	-11.71	-9.63	11.76	7.30	0.046	0.18
10	6	10	-88.59	-130.31	89.66	-121.12	1.067	4.64
11	7	8	115.00	26.84	-112.88	-20.35	2.118	8.18
12	8	9	-36.92	3.36	37.53	-5.46	0.604	2.34
13	8	10	-21.19	-18.01	21.50	14.61	0.303	1.17
14	9	11	-105.92	-12.77	106.20	22.87	0.277	10.10
15	9	12	-120.47	-25.69	120.84	39.16	0.369	13.47
16	10	11	-151.18	36.03	151.72	-16.10	0.546	19.93
17	10	12	-166.74	23.18	167.38	0.21	0.641	23.39
18	11	13	-86.15	-54.97	86.76	49.70	0.618	4.82

19	11	14	-171.77	48.19	173.55	-42.96	1.778	13.76
20	12	13	-60.51	-33.30	60.79	25.20	0.271	2.11
21	12	23	-227.70	-6.07	234.10	34.52	6.399	49.85
22	13	23	-225.30	5.10	230.74	17.80	5.438	42.38
23	14	16	-367.55	-23.77	374.60	70.49	7.054	54.88
24	15	16	112.30	-32.60	-112.01	31.13	0.290	2.28
25	15	21	-214.92	-41.97	217.83	53.65	2.913	22.65
26	15	21	-214.92	-41.97	217.83	53.65	2.913	22.65
27	15	24	215.54	48.59	-212.32	-34.48	3.219	24.93
28	16	17	-322.68	-33.86	326.03	54.42	3.353	26.31
29	16	19	115.08	-43.35	-114.65	41.64	0.433	3.33
30	17	18	-186.94	-58.69	187.58	60.49	0.638	5.10
31	17	22	-139.09	4.28	141.54	-9.26	2.454	19.14
32	18	21	-60.29	5.12	60.40	-10.26	0.111	0.87
33	18	21	-60.29	5.12	60.40	-10.26	0.111	0.87
34	19	20	-33.17	-39.32	33.29	31.34	0.113	0.88
35	19	20	-33.17	-39.32	33.29	31.34	0.113	0.88
36	20	23	-97.29	-44.34	97.58	41.63	0.291	2.25
37	20	23	-97.29	-44.34	97.58	41.63	0.291	2.25
38	21	22	-156.46	20.12	158.46	-20.29	1.994	15.54
							--------	--------
					Total:		51.246	454.77

APPENDIX C-2

POWER FLOW SIMULATION RESULTS FOR LOAD PD1 (PD+10%PD)

```
Newton's method power flow converged in 4 iterations.

Converged in 0.58 seconds
========================================================================
========
|     System Summary
|
========================================================================
========

How many?                How much?              P (MW)            Q
(MVAr)
---------------------    -------------------  -------------  -----------
------
Buses              24     Total Gen Capacity    3405.0        -535.0 to
1776.0
Generators         33     On-line Capacity      3405.0        -535.0 to
1776.0
Committed Gens     33     Generation (actual)   3185.7           610.6
Loads              17     Load                  3135.0           580.0
  Fixed            17       Fixed               3135.0           580.0
  Dispatchable      0       Dispatchable           0.0 of 0.0       0.0
Shunts              1     Shunt (inj)              0.0          -101.3
Branches           38     Losses (I^2 * Z)       50.66           475.80
Transformers        5     Branch Charging (inj)     -            546.4
Inter-ties         10     Total Inter-tie Flow  1424.4           201.1
Areas               4

                          Minimum                      Maximum
                 -------------------------  ----------------------------
----
Voltage Magnitude   0.976 p.u. @ bus 24         1.050 p.u. @ bus 22
Voltage Angle     -17.51 deg   @ bus 6        17.52 deg   @ bus 22
P Losses (I^2*R)             -                  6.00 MW    @ line 14-16
Q Losses (I^2*X)             -                46.68 MVAr  @ line 14-16
```

```
========================================================================
========
|     Bus Data
|
========================================================================
========
```

Bus #	Voltage Mag(pu)	Voltage Ang(deg)	Generation P (MW)	Generation Q (MVAr)	Load P (MW)	Load Q (MVAr)
1	1.035	-12.973	172.00	30.25	118.80	22.00
2	1.035	-13.056	172.00	24.00	106.70	20.00
3	0.985	-11.072	-	-	198.00	37.00
4	0.994	-14.874	-	-	81.40	15.00
5	1.015	-15.204	-	-	78.10	14.00
6	1.006	-17.507	-	-	149.60	28.00
7	1.025	-13.749	240.00	61.22	137.50	25.00
8	0.988	-16.976	-	-	188.10	35.00
9	0.997	-11.723	-	-	192.50	36.00
10	1.023	-13.903	-	-	214.50	40.00
11	0.986	-5.037	-	-	-	-
12	0.997	-3.908	-	-	-	-
13	1.020	0.000	471.66	122.83	291.50	54.00
14	0.980	-1.854	0.00	-23.03	213.40	39.00
15	1.014	6.367	215.00	3.02	348.70	64.00
16	1.017	5.654	155.00	39.41	110.00	20.00
17	1.039	9.766	-	-	-	-
18	1.050	10.939	400.00	140.90	366.30	68.00
19	1.023	4.727	-	-	199.10	37.00
20	1.038	6.041	-	-	140.80	26.00
21	1.050	11.823	400.00	106.49	-	-
22	1.050	17.522	300.00	-29.81	-	-
23	1.050	7.529	660.00	135.35	-	-
24	0.976	0.019	-	-	-	-
		Total:	3185.66	610.62	3135.00	580.00

```
========================================================================
========
|     Branch Data
|
========================================================================
========
```

Brnch #	From Bus	To Bus	From Bus Injection P (MW)	Q (MVAr)	To Bus Injection P (MW)	Q (MVAr)	Loss (I^2 * Z) P (MW)	Q (MVAr)
-----	-----	-----	--------	--------	--------	--------	--------	--------
1	1	2	10.68	-26.69	-10.68	-22.69	0.003	0.02
2	1	3	-9.00	24.07	9.42	-28.29	0.416	1.61
3	1	5	51.52	10.88	-50.95	-11.07	0.570	2.21
4	2	4	32.36	23.63	-31.85	-25.15	0.519	2.01
5	2	6	43.61	3.07	-42.72	-5.01	0.898	3.47
6	3	9	6.40	-13.07	-6.34	10.12	0.055	0.21
7	3	24	-213.82	4.36	214.97	37.60	1.150	41.97
8	4	9	-49.55	10.15	50.26	-10.22	0.702	2.72
9	5	10	-27.15	-2.93	27.31	1.08	0.164	0.63
10	6	10	-106.88	-124.24	108.45	-122.06	1.568	6.83
11	7	8	102.50	36.22	-100.70	-30.96	1.798	6.94
12	8	9	-51.84	8.67	53.07	-8.34	1.226	4.74
13	8	10	-35.56	-12.72	36.16	10.52	0.601	2.32
14	9	11	-132.66	-9.30	133.09	25.14	0.434	15.84
15	9	12	-156.82	-18.26	157.44	40.59	0.612	22.33
16	10	11	-180.52	39.40	181.30	-10.91	0.781	28.48
17	10	12	-205.90	31.07	206.89	5.11	0.992	36.17
18	11	13	-190.36	-43.17	192.73	51.59	2.367	18.47

19	11	14	-124.03	28.95	124.95	-30.35	0.916	7.09
20	12	13	-148.76	-29.77	150.15	30.51	1.397	10.90
21	12	23	-215.57	-15.92	221.38	39.87	5.805	45.22
22	13	23	-162.72	-13.28	165.55	15.83	2.826	22.03
23	14	16	-338.35	-31.68	344.35	70.21	6.000	46.68
24	15	16	70.81	-28.00	-70.69	25.20	0.122	0.96
25	15	21	-211.40	-42.77	214.23	53.76	2.824	21.97
26	15	21	-211.40	-42.77	214.23	53.76	2.824	21.97
27	15	24	218.29	52.56	-214.97	-37.60	3.326	25.76
28	16	17	-297.20	-39.94	300.06	56.64	2.862	22.46
29	16	19	68.54	-36.06	-68.37	32.32	0.169	1.30
30	17	18	-162.34	-60.76	162.84	61.44	0.498	3.98
31	17	22	-137.72	4.12	140.12	-9.49	2.405	18.76
32	18	21	-64.57	5.73	64.70	-10.74	0.127	1.00
33	18	21	-64.57	5.73	64.70	-10.74	0.127	1.00
34	19	20	-65.37	-34.66	65.62	27.78	0.253	1.97
35	19	20	-65.37	-34.66	65.62	27.78	0.253	1.97
36	20	23	-136.02	-40.78	136.54	39.83	0.519	4.00
37	20	23	-136.02	-40.78	136.54	39.83	0.519	4.00
38	21	22	-157.85	20.44	159.88	-20.33	2.029	15.81
							-------- -	
					Total:	50.660	475.80	

APPENDIX C-3

POWER FLOW SIMULATION RESULTS FOR PD2 (PD1+10%PD1)

```
Newton's method power flow converged in 4 iterations.

Converged in 0.03 seconds
================================================================================
|     System Summary                                                           |
================================================================================

How many?                How much?              P (MW)            Q (MVAr)
---------------------    -------------------  -------------  -----------------
Buses              24     Total Gen Capacity    3405.0        -535.0 to 1776.0
Generators         33     On-line Capacity      3405.0        -535.0 to 1776.0
Committed Gens     33     Generation (actual)   3505.7             696.3
Loads              17     Load                  3448.5             580.0
  Fixed            17       Fixed               3448.5             580.0
  Dispatchable      0       Dispatchable           0.0 of 0.0        0.0
Shunts              1     Shunt (inj)              0.0             -99.3
Branches           38     Losses (I^2 * Z)        57.15            557.76
Transformers        5     Branch Charging (inj)     -              540.7
Inter-ties         10     Total Inter-tie Flow  1518.4             211.1
Areas               4

                          Minimum                      Maximum
                 -------------------------  --------------------------------
Voltage Magnitude   0.973 p.u. @ bus 24          1.050 p.u. @ bus 18
Voltage Angle     -23.78 deg   @ bus 8          11.63 deg   @ bus 22
P Losses (I^2*R)             -                   6.00 MW    @ line 11-13
Q Losses (I^2*X)             -                  54.17 MVAr  @ line 10-12
```

```
================================================================================
|     Bus Data                                                                 |
================================================================================
 Bus      Voltage          Generation             Load
  #   Mag(pu) Ang(deg)   P (MW)   Q (MVAr)   P (MW)   Q (MVAr)
----- ------- --------  --------  --------  --------  --------
    1  1.035  -19.541    172.00     43.29    130.68     22.00
    2  1.035  -19.614    172.00     36.65    117.37     20.00
    3  0.978  -17.337       -         -      217.80     37.00
    4  0.988  -20.847       -         -       89.54     15.00
    5  1.009  -21.249       -         -       85.91     14.00
    6  0.996  -23.381       -         -      164.56     28.00
    7  1.025  -21.136    240.00     75.01    151.25     25.00
    8  0.982  -23.779       -         -      206.91     35.00
    9  0.989  -16.640       -         -      211.75     36.00
   10  1.013  -18.969       -         -      235.95     40.00
   11  0.979   -8.307       -         -         -         -
   12  0.987   -6.610       -         -         -         -
   13  1.020    0.000    791.65    136.87    320.65     54.00
   14  0.980   -6.504      0.00     -9.89    234.74     39.00
   15  1.014    0.519    215.00     12.77    383.57     64.00
   16  1.017    0.258    155.00     36.79    121.00     20.00
   17  1.039    3.960       -         -         -         -
   18  1.050    4.923    400.00    143.55    402.93     68.00
   19  1.022    0.013       -         -      219.01     37.00
   20  1.037    2.117       -         -      154.88     26.00
   21  1.050    5.871    400.00    106.07       -         -
   22  1.050   11.626    300.00    -30.08       -         -
   23  1.050    4.105    660.00    145.31       -         -
   24  0.973   -5.943       -         -         -         -
                        --------  --------  --------  --------
               Total:   3505.65    696.33   3448.50    580.00

================================================================================
|     Branch Data                                                              |
================================================================================
```

Brnch #	From Bus	To Bus	From Bus Injection P (MW)	From Bus Injection Q (MVAr)	To Bus Injection P (MW)	To Bus Injection Q (MVAr)	Loss (I^2 * Z) P (MW)	Loss (I^2 * Z) Q (MVAr)
1	1	2	9.47	-26.46	-9.47	-22.92	0.002	0.01
2	1	3	-10.45	27.82	10.99	-31.53	0.542	2.10
3	1	5	42.30	19.93	-41.85	-20.56	0.455	1.76
4	2	4	25.69	30.35	-25.17	-31.85	0.519	2.01
5	2	6	38.40	9.22	-37.65	-11.69	0.751	2.90
6	3	9	-11.33	-7.15	11.38	4.24	0.051	0.20
7	3	24	-217.46	1.68	218.67	42.31	1.206	43.99
8	4	9	-64.37	16.85	65.59	-14.84	1.229	4.76
9	5	10	-44.06	6.56	44.51	-7.27	0.448	1.74
10	6	10	-126.91	-115.60	129.17	-122.86	2.261	9.84
11	7	8	88.75	50.01	-87.17	-45.57	1.584	6.12
12	8	9	-68.37	15.99	70.59	-11.76	2.217	8.57
13	8	10	-51.37	-5.43	52.55	5.52	1.174	4.54
14	9	11	-162.39	-5.09	163.05	29.13	0.659	24.04
15	9	12	-196.93	-8.54	197.90	43.92	0.970	35.38
16	10	11	-213.16	43.36	214.26	-3.12	1.103	40.23
17	10	12	-249.01	41.25	250.50	12.92	1.485	54.17
18	11	13	-306.03	-28.76	312.03	65.62	6.003	46.84

19	11	14	-71.28	2.76	71.57	-8.95	0.289	2.24
20	12	13	-246.39	-27.36	250.22	47.20	3.832	29.90
21	12	23	-202.01	-29.48	207.25	49.23	5.241	40.83
22	13	23	-91.25	-29.95	92.19	17.74	0.933	7.27
23	14	16	-306.31	-39.95	311.26	70.32	4.952	38.53
24	15	16	24.50	-22.51	-24.48	18.93	0.022	0.17
25	15	21	-207.61	-43.63	210.34	53.89	2.731	21.24
26	15	21	-207.61	-43.63	210.34	53.89	2.731	21.24
27	15	24	222.15	58.53	-218.67	-42.31	3.484	26.99
28	16	17	-268.94	-46.38	271.30	59.21	2.368	18.59
29	16	19	16.15	-26.08	-16.13	21.22	0.024	0.18
30	17	18	-135.12	-63.13	135.49	62.76	0.367	2.94
31	17	22	-136.19	3.92	138.54	-9.71	2.351	18.34
32	18	21	-69.21	6.40	69.35	-11.26	0.146	1.15
33	18	21	-69.21	6.40	69.35	-11.26	0.146	1.15
34	19	20	-101.44	-29.11	101.97	24.41	0.533	4.13
35	19	20	-101.44	-29.11	101.97	24.41	0.533	4.13
36	20	23	-179.41	-37.41	180.28	39.17	0.870	6.71
37	20	23	-179.41	-37.41	180.28	39.17	0.870	6.71
38	21	22	-159.39	20.80	161.46	-20.37	2.070	16.13
							--------	-
					Total:	57.151	557.76	

APPENDIX C-4

POWER FLOW SIMULATION RESULTS FOR PD3 (PD2+10%PD2)

```
Newton's method power flow converged in 4 iterations.

Converged in 0.00 seconds
========================================================================
========
|     System Summary
|
========================================================================
========

How many?                How much?              P (MW)            Q
(MVAr)
---------------------    -------------------  -------------  -----------
------
Buses              24     Total Gen Capacity    3405.0        -535.0 to
1776.0
Generators         33     On-line Capacity      3405.0        -535.0 to
1776.0
Committed Gens     33     Generation (actual)   3867.7             874.9
Loads              17     Load                  3793.3             580.0
  Fixed            17       Fixed               3793.3             580.0
Dispatchable     0        Dispatchable           0.0 of 0.0        0.0
Shunts              1     Shunt (inj)              0.0             -96.3
Branches           38     Losses (I^2 * Z)       74.30             730.35
Transformers        5     Branch Charging (inj)     -              531.7
Inter-ties         10     Total Inter-tie Flow  1710.6             230.8
Areas               4

                          Minimum                      Maximum
                 -------------------------  ----------------------------
----
Voltage Magnitude   0.967 p.u. @ bus 11         1.050 p.u. @ bus 21
Voltage Angle     -31.86 deg   @ bus 8          4.91 deg   @ bus 22
P Losses (I^2*R)             -                 12.34 MW    @ line 11-13
Q Losses (I^2*X)             -                 96.26 MVAr  @ line 11-13
```

```
================================================================================
========
|     Bus Data
|
================================================================================
========
```

Bus #	Voltage Mag(pu)	Voltage Ang(deg)	Generation P (MW)	Generation Q (MVAr)	Load P (MW)	Load Q (MVAr)
1	1.035	-27.314	172.00	62.70	143.75	22.00
2	1.035	-27.380	172.00	55.74	129.11	20.00
3	0.968	-24.648	-	-	239.58	37.00
4	0.977	-27.913	-	-	98.49	15.00
5	1.000	-28.412	-	-	94.50	14.00
6	0.981	-30.359	-	-	181.02	28.00
7	1.025	-29.914	240.00	95.39	166.38	25.00
8	0.971	-31.864	-	-	227.60	35.00
9	0.975	-22.421	-	-	232.93	36.00
10	0.997	-24.958	-	-	259.55	40.00
11	0.967	-12.089	-	-	-	-
12	0.972	-9.714	-	-	-	-
13	1.020	0.000	1153.65	188.67	352.71	54.00
14	0.980	-11.854	0.00	15.82	258.21	39.00
15	1.014	-6.153	215.00	26.67	421.93	64.00
16	1.017	-5.904	155.00	37.63	133.10	20.00
17	1.039	-2.658	-	-	-	-
18	1.050	-1.926	400.00	146.79	443.22	68.00
19	1.021	-5.364	-	-	240.91	37.00
20	1.036	-2.359	-	-	170.37	26.00
21	1.050	-0.910	400.00	105.67	-	-
22	1.050	4.909	300.00	-30.35	-	-
23	1.050	0.194	660.00	170.21	-	-
24	0.968	-12.787	-	-	-	-
		Total:	3867.65	874.94	3793.35	580.00

```
================================================================================
========
|     Branch Data
|
================================================================================
========
```

Brnch #	From Bus	To Bus	From Bus Injection P (MW)	From Bus Injection Q (MVAr)	To Bus Injection P (MW)	To Bus Injection Q (MVAr)	Loss (I^2 * Z) P (MW)	Loss (I^2 * Z) Q (MVAr)
1	1	2	8.46	-26.27	-8.46	-23.11	0.002	0.01
2	1	3	-12.62	33.51	13.38	-36.30	0.763	2.95
3	1	5	32.41	33.47	-31.95	-34.06	0.459	1.78
4	2	4	18.37	40.42	-17.72	-41.38	0.650	2.51
5	2	6	32.98	18.44	-32.27	-20.97	0.714	2.76
6	3	9	-30.04	1.48	30.34	-3.36	0.299	1.16
7	3	24	-222.92	-2.18	224.22	49.38	1.294	47.20
8	4	9	-80.77	26.38	82.82	-21.14	2.045	7.91
9	5	10	-62.55	20.06	63.54	-18.59	0.995	3.85
10	6	10	-148.75	-103.29	151.98	-123.31	3.228	14.05
11	7	8	73.63	70.39	-72.04	-65.91	1.589	6.14
12	8	9	-86.78	26.19	90.54	-15.85	3.769	14.57
13	8	10	-68.79	4.71	70.95	-0.69	2.162	8.36
14	9	11	-195.56	0.05	196.54	35.78	0.982	35.83
15	9	12	-241.07	4.31	242.56	50.16	1.493	54.46
16	10	11	-249.62	48.05	251.17	8.65	1.555	56.71
17	10	12	-296.40	54.53	298.59	25.18	2.185	79.71
18	11	13	-434.67	-11.27	447.00	97.67	12.336	96.26

19	11	14	-13.04	-33.16	13.10	25.29	0.059	0.45
20	12	13	-354.38	-27.14	362.52	80.72	8.138	63.50
21	12	23	-186.77	-48.19	191.54	64.59	4.772	37.18
22	13	23	-8.58	-43.72	8.71	25.28	0.133	1.04
23	14	16	-271.32	-48.46	275.25	70.93	3.936	30.62
24	15	16	-27.69	-15.88	27.71	12.29	0.021	0.16
25	15	21	-203.59	-44.53	206.23	54.04	2.634	20.49
26	15	21	-203.59	-44.53	206.23	54.04	2.634	20.49
27	15	24	227.95	67.60	-224.22	-49.38	3.735	28.93
28	16	17	-237.45	-53.19	239.33	62.18	1.880	14.75
29	16	19	-43.61	-12.39	43.67	7.80	0.058	0.45
30	17	18	-104.87	-65.85	105.12	64.56	0.252	2.02
31	17	22	-134.46	3.66	136.75	-9.93	2.290	17.87
32	18	21	-74.17	7.12	74.34	-11.81	0.168	1.32
33	18	21	-74.17	7.12	74.34	-11.81	0.168	1.32
34	19	20	-142.29	-22.40	143.30	21.41	1.007	7.82
35	19	20	-142.29	-22.40	143.30	21.41	1.007	7.82
36	20	23	-228.48	-34.41	229.87	40.17	1.388	10.71
37	20	23	-228.48	-34.41	229.87	40.17	1.388	10.71
38	21	22	-161.14	21.21	163.25	-20.42	2.116	16.49
							--------	--------
					Total:		74.304	730.35

APPENDIX C-5

POWER FLOW SIMULATION RESULTS FOR PD4

(PD3+10%PD3)

```
Newton's method power flow converged in 5 iterations.

Converged in 0.02 seconds
========================================================================
========
|     System Summary
|
========================================================================
========

How many?                How much?              P (MW)            Q
(MVAr)
---------------------    -------------------  -------------  -----------
------
Buses              24     Total Gen Capacity    3405.0        -535.0 to
1776.0
Generators         33     On-line Capacity      3405.0        -535.0 to
1776.0
Committed Gens     33     Generation (actual)   4281.4            1202.0
Loads              17     Load                  4172.7             580.0
  Fixed            17       Fixed               4172.7             580.0
  Dispatchable      0       Dispatchable           0.0 of 0.0        0.0
Shunts              1     Shunt (inj)            0.0             -91.5
Branches           38     Losses (I^2 * Z)       108.72          1047.74
Transformers        5     Branch Charging (inj)     -             517.2
Inter-ties         10     Total Inter-tie Flow  1968.5             274.7
Areas               4

                          Minimum                      Maximum
                 -------------------------  ----------------------------
----
Voltage Magnitude   0.947 p.u. @ bus 11         1.050 p.u. @ bus 18
Voltage Angle     -41.97 deg   @ bus 8          0.00 deg   @ bus 13
P Losses (I^2*R)             -                22.75 MW    @ line 11-13
Q Losses (I^2*X)             -               177.53 MVAr  @ line 11-13
```

```
========================================================================
========
|     Bus Data
|
========================================================================
========
```

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
1	1.035	-36.952	172.00	92.63	158.12	22.00
2	1.035	-37.014	172.00	85.47	142.02	20.00
3	0.952	-33.518	-	-	263.54	37.00
4	0.961	-36.677	-	-	108.34	15.00
5	0.985	-37.319	-	-	103.95	14.00
6	0.957	-39.065	-	-	199.12	28.00
7	1.025	-40.872	240.00	126.61	183.01	25.00
8	0.955	-41.966	-	-	250.36	35.00
9	0.951	-29.520	-	-	256.22	36.00
10	0.971	-32.382	-	-	285.50	40.00
11	0.947	-16.607	-	-	-	-
12	0.948	-13.382	-	-	-	-
13	1.020	0.000	1567.40	300.59	387.99	54.00
14	0.980	-18.192	0.00	61.73	284.04	39.00
15	1.014	-13.954	215.00	47.48	464.12	64.00
16	1.017	-13.118	155.00	43.70	146.41	20.00
17	1.039	-10.383	-	-	-	-
18	1.050	-9.910	400.00	150.72	487.54	68.00
19	1.019	-11.652	-	-	265.00	37.00
20	1.034	-7.596	-	-	187.40	26.00
21	1.050	-8.823	400.00	105.32	-	-
22	1.050	-2.931	300.00	-30.61	-	-
23	1.050	-4.391	660.00	218.39	-	-
24	0.960	-20.876	-	-	-	-
		Total:	4281.40	1202.03	4172.68	580.00

```
========================================================================
========
|     Branch Data
|
========================================================================
========
```

Brnch #	From Bus	To Bus	From Bus Injection P (MW)	From Bus Injection Q (MVAr)	To Bus Injection P (MW)	To Bus Injection Q (MVAr)	Loss (I^2 * Z) P (MW)	Loss (I^2 * Z) Q (MVAr)
1	1	2	8.01	-26.19	-8.01	-23.20	0.002	0.01
2	1	3	-16.18	42.48	17.37	-43.53	1.191	4.61
3	1	5	22.05	54.34	-21.32	-53.86	0.727	2.82
4	2	4	10.34	55.97	-9.29	-55.31	1.056	4.08
5	2	6	27.64	32.69	-26.70	-34.23	0.938	3.63
6	3	9	-49.06	14.05	49.95	-13.50	0.899	3.47
7	3	24	-231.85	-7.52	233.30	60.34	1.448	52.82
8	4	9	-99.05	40.31	102.40	-29.92	3.350	12.96
9	5	10	-82.63	39.86	84.62	-34.40	2.000	7.74
10	6	10	-172.42	-85.26	177.05	-122.99	4.629	20.15
11	7	8	56.99	101.61	-54.91	-95.20	2.081	8.04
12	8	9	-107.46	40.90	113.73	-20.72	6.270	24.24
13	8	10	-87.99	19.30	91.83	-8.60	3.839	14.84
14	9	11	-232.82	6.44	234.28	46.93	1.463	53.38
15	9	12	-289.49	21.69	291.76	61.23	2.273	82.92
16	10	11	-290.72	53.69	292.94	27.23	2.218	80.92
17	10	12	-348.28	72.31	351.49	44.85	3.212	117.15
18	11	13	-578.36	9.63	601.11	158.22	22.751	177.53

19	11	14	51.14	-83.80	-50.59	79.82	0.541	4.19
20	12	13	-473.77	-31.50	489.04	141.02	15.276	119.20
21	12	23	-169.49	-74.57	174.04	89.71	4.552	35.46
22	13	23	89.26	-52.65	-88.21	41.35	1.049	8.17
23	14	16	-233.45	-57.09	236.43	72.15	2.984	23.22
24	15	16	-87.64	-7.68	87.81	5.22	0.165	1.30
25	15	21	-199.48	-45.44	202.01	54.20	2.537	19.73
26	15	21	-199.48	-45.44	202.01	54.20	2.537	19.73
27	15	24	237.48	82.04	-233.30	-60.34	4.176	32.34
28	16	17	-202.09	-60.38	203.50	65.68	1.409	11.06
29	16	19	-113.56	6.71	113.94	-8.83	0.377	2.90
30	17	18	-71.03	-69.00	71.19	66.97	0.160	1.28
31	17	22	-132.47	3.33	134.69	-10.14	2.222	17.33
32	18	21	-79.36	7.87	79.56	-12.37	0.192	1.51
33	18	21	-79.36	7.87	79.56	-12.37	0.192	1.51
34	19	20	-189.47	-14.08	191.24	19.04	1.769	13.74
35	19	20	-189.47	-14.08	191.24	19.04	1.769	13.74
36	20	23	-284.94	-32.04	287.08	43.67	2.147	16.56
37	20	23	-284.94	-32.04	287.08	43.67	2.147	16.56
38	21	22	-163.14	21.67	165.31	-20.47	2.169	16.90
							--------	-
						Total:	108.716	1047.74

APPENDIX D

TRANSMISSION LOSS ALGORITHMS

```
%************************************PRO                              RATA
generators**********************
%Pg=total active power generated
%Pd=total active power demand
%Pgi=power output of generators of bus i
%L=transmission power losses
%Lgi=losses allocated to generator i
%Lgi=(L/2)*(Pgi/Pg)
%Generators are at bus [1 2 7 13 15 16 18 21 22 23]

%calculating the losses

Pgi = [172 172 240 187.25 215 155 400 400 300 660];
Pd = 2850;
Pg=2901.25;
L = Pg-Pd;
Lgi=(L/2)*(Pgi/Pg)


%*****************************PRO RATA LOADS***************8

%Pg=total active power generated
%Pd=total active power demand
%Pgi=power output of generators of bus i
%L=transmission power losses
%Lgi=losses allocated to generator i
%Lgi=(L/2)*(Pgi/Pg)
%Generators are at bus [1 2 7 13 15 16 18 21 22 23]

%calculating the losses

Pdj = [108 97 180 74 71 136 125 171 175 195 266 194 317 100 333 181
128];
Pd = 2850;
Pg=2901.25;
L = Pg-Pd;
Ldj=(L/2)*(Pdj/Pd)



%*******************INCREMENTAL
ALLOCATION(ITL)generator****************

%Ploss=system transmission losses
%Pi is power injection at individual loads
%Ki=ITL corresponding to bus i
%Lgi_final=losses allocated to each genear
Pgi = [172 172 240 187.25 215 155 400 400 300 660];

Pdi = [108 97 125 265 317 100 333 0 0 0 ];
L=51.52;

%calculating Ki
Pi=Pgi-Pdi;
Ki=L./Pi;

Lgi3=Pgi.*Ki;
L_sum=sum(Lgi3);
```

```
Ki_new = Ki.*(L./L_sum);
Lgi_final = Pgi.*Ki_new


%Ploss_total = 51.52; %taken from pf solution
%Pi=[108 97 125 265 317 100 333 0 0 0];

%Ploss=Ploss_total./Pi


%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%ITL loads*************************8

%Ploss=system transmission losses
%Pi is power injection at individual loads
%Ki=ITL corresponding to bus i
%Lgi_final=losses allocated to each genearator

Pdj = [108 97 180 74 71 136 125 171 175 195 265 194 317 100 333 181
128];
Pd = 2850;

PgiL = [172 172 0 0 0 0 240 0 0 0 187.25 0 215 155 400 0 0];

L=51.52;

%calculating Ki
Pi=PgiL-Pdj;
Ki=L./Pi;

Ldj2=PgiL.*Ki;
L_sum=sum(Ldj2);
Ki_new = Ki.*(L./L_sum)
Ldj2_final = Pdj.*Ki_new;



%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%Unsubdised
ITL(generators)***************

Pgi = [172 172 240 187.25 215 155 400 400 300 660];
Ki_new = [0.0561 0.0479 0.0312 -0.0462 -0.0352 0.0653 0.0536 0.0090
0.0120 0.0054]
Kgk = -0.0462;

Bg = 1/(1-Kgk);

Kgi = Bg.*Ki_new + (1-Bg);

Lgi4 = Kgi.* Pgi


%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%Unsubdised
ITL(loads)****************

Pdj = [108 97 180 74 71 136 125 171 175 195 265 194 317 100 333 181
128];
Ki_new =[0.0710 0.0606 -0.0252 -0.0614 -0.0640 -0.0334 0.0395 -0.0266 -
0.0260 -0.0233 -0.0584 -0.0234 -0.0445 0.0826 0.0678 -0.0251 -0.0355]
Kgk = 0.0826;

Bd = 1/(1-Kgk);

Kdi = Bd.*Ki_new + (1-Bd);
```

```
Ldj4 = -Kdi.* Pdj


%***********************PS generator******************************

Pin=  [64  86.94  -58.11  -207.6  -225.3  -102  -207.6    -156.46  0  0];
%calculated in the  load flow
Pout= [-62.92 -85.26 -112.88 230.74 111.33 211.38 120.8 0 0];
LossG=(Pin+Pout)/2


%%%%%%%%%%%%%%%%%%%%%%%PS loads**********************************


Pin= [64 86.94 -188.31 -36.15 -11.71 -88.59 115 -58.11 -226.39 -317.92 -
225.30 -367.55 -102 -207.6 -120.58 -66.34 -194.58]; %calculated in the
load flow
Pout= [-62.92 -85.26 189.66 36.52 11.76 89.66 -112.88 59.03 229.2 319.1
230.74 374.6 111.33 211.38 120.8 66.58 195.16];%calculated in the load
flow

LossL=(Pin+Pout)/2


%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%Plot
generators%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
PR_G  =[1.5192  1.5192  2.1198  1.6539  1.899  1.369  3.533  3.533  2.6497
5.8294];
PS_G = [1.0800      1.6800      2.1200      5.4400      9.3300      3.7800
0.2200    2.0000 0 0];
BusG = [1 2 7 13 15 16 18 21 22 23];
ITL_G =  [9.6556  8.2394  7.4980  -8.6527  -7.5730  10.1251  21.4494  3.5928
3.5928 3.5928]
UITL_G = [16.8186 15.4705 17.7557 0.0000 2.2606 16.5193 38.1571 21.1050
16.6890 32.5521];

figure(1)
plot(BusG,PR_G,'blue')
title('Losses allocated to generators (MW)')
xlabel('Bus')
ylabel('Losses (MW)')

hold on
plot(BusG,PS_G,'red')

hold on
plot(BusG,ITL_G,'yellow')

hold on
plot(BusG,UITL_G,'green')



%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%PLOT LOADS**********************

BusL = [1 2 3 4 5 6 7 8 9 10 13 14 15 16 18 19 20];
PR_L = [0.9711 0.8721 1.6184 0.6654 0.6384 1.2228 1.1239 1.5375 1.5735
1.7533 2.3917 1.7443 2.8502 0.8991 2.9941 1.6274 1.1509];
PS_L = [0.5400 0.8400 0.6750 0.1850 0.0250 0.5350 1.0600 0.4600 1.4050
0.5900 2.7200 3.5250 4.6650 1.8900 0.1100 0.1200 0.2900];
ITL_L = [7.6667 5.8759 -4.5432 -4.5432 -4.5432 -4.5432 4.9383 -4.5432 -
4.5432  -4.5432  -15.4850  -4.5432  -14.1197  8.2604  22.5806  -4.5432  -
4.5432];
```

```
UITL_L = [1.3656 2.3261 21.1511 11.6154 11.3458 17.1964 5.8726 20.3545
20.7162 22.5098 40.7292 22.4155 43.9184 0.0000 5.3721 21.2489 16.4779];

figure(2)
plot(BusL,PR_L,'blue')
title('Losses allocated to loads (MW)')
xlabel('Bus')
ylabel('Losses (MW)')

hold on
plot(BusL,PS_L,'red')

hold on
plot(BusL,ITL_L,'yellow')

hold on
plot(BusL,UITL_L,'green')


%******************************correlation**********************

figure(3)
crosscorr(PS_L,PR_L)
title('PS_L&PR_L')

figure(4)
crosscorr(PS_L,ITL_L)
title('PS_L&ITL_L')

figure(5)
crosscorr(PS_L,UITL_L)
title('PS_L&UITL_L')

figure(6)
crosscorr(PR_L,ITL_L)
title('PR_L&ITL_L')

figure(7)
crosscorr(PR_L,UITL_L)
title('PR_L&UITL_L')

figure(8)
crosscorr(ITL_L,UITL_L)
title('ITL_L&UITL_L')
```

APPENDIX E

PREDICTION USING MATLAB

```
%%%%%%%%%%%%%%%%%%%%%%%%%%Bus 1%%%%%%%%%%%%%%%%%%%%

Pd1=1.188;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.00989;
Losst2 = 0.00999;
Losst3 = 0.01224;
%Losst4 = 0.0192;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B

Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%Bus 2%%%%%%%%%%%%%%%%%%%%

Pd1=1.067;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.01417;
Losst2 = 0.0127;
Losst3 = 0.01364;
%Losst4 = 0.01994;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B

Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%Bus 3%%%%%%%%%%%%%%%%%%%%

Pd1=1.98;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.01205;
Losst2 = 0.01257;
Losst3 = 0.01593;
%Losst4 = 0.02347;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B
```

```
Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%Bus 4%%%%%%%%%%%%%%%%%%%%

Pd1=0.814;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.0072;
Losst2 = 0.01229;
Losst3 = 0.02045;
%Losst4 = 0.0335;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B


Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%Bus 5%%%%%%%%%%%%%%%%%%%%

Pd1=0.781;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.00164;
Losst2 = 0.00448;
Losst3 = 0.0095;
%Losst4 = 0.02;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B

Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%Bus 6%%%%%%%%%%%%%%%%%%%%

Pd1=1.496;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.01568;
Losst2 = 0.02261;
Losst3 = 0.03228;
%Losst4 = 0.04629;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B


Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4
```

```
%%%%%%%%%%%%%%%%%%%%%%%%%%Bus 7%%%%%%%%%%%%%%%%%%%%

Pd1=1.375;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.01798;
Losst2 = 0.01584;
Losst3 = 0.01589;
%Losst4 = 0.02081;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B


Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4


%%%%%%%%%%%%%%%%%%%%%%%%%%Bus 8%%%%%%%%%%%%%%%%%%%%
Pd1=1.881;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.01827;
Losst2 = 0.03391;
Losst3 = 0.05931;
%Losst4 = 0.10109;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B

Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%Bus 9%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

Pd1=1.925;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.01046;
Losst2 = 0.01629;
Losst3 = 0.02475;
%Losst4 = 0.03736;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B


Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%Bus10%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
Pd1=2.145;
```

```
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.01773;
Losst2 = 0.02588;
Losst3 = 0.0374;
%Losst4 = 0.0543;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B


Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%Bus13%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

Pd1=2.915;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.02826;
Losst2 = 0.00933;
Losst3 = 0.00133;
%Losst4 = 0.01049;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B


Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%Bus14%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

Pd1=2.134;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.06;
Losst2 = 0.04952;
Losst3 = 0.03936;
%Losst4 = 0.02984;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B

Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%Bus 15%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%


Pd1=3.487;
Pd2=Pd1*0.1+Pd1;
```

```
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;
Losst1 = 0.09096;
Losst2 = 0.08968;
Losst3 = 0.09024;
%Losst4 = 0.09415;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B

Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%Bus16%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

Pd1=1.10;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.03031;
Losst2 = 0.02392;
Losst3 = 0.01938;
%Losst4 = 0.01786;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B


Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%Bus18%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

Pd1=3.663;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.00254;
Losst2 = 0.00292;
Losst3 = 0.00336;
%Losst4 = 0.00384;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B


Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%Bus19%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

Pd1=1.991;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;
```

```
Losst1 = 0.00506;
Losst2 = 0.01066;
Losst3 = 0.02014;
%Losst4 = 0.03538;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B


Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4

%%%%%%%%%%%%%%%%%%%%%%%%%%Bus 20%%%%%%%%%%%%%%%%%%%%
Pd1=1.408;
Pd2=Pd1*0.1+Pd1;
Pd3=Pd2*0.1+Pd2;
Pd4=Pd3*0.1+Pd3;

Losst1 = 0.01038;
Losst2 = 0.0174;
Losst3 = 0.02776;
%Losst4 = 0.04294;

A = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];
B = [Losst1;Losst2;Losst3];
C = [1/Pd1 1 Pd1;1/Pd2 1 Pd2;1/Pd3 1 Pd3];

Coeff = inv(A)*B


Losst4 = Coeff(1,1)/Pd4 + Coeff(2,1) + Coeff(3,1)*Pd4
```